STAFF'S REVISED FORECAST OF NATURAL GAS PRODUCTION AND WELLHEAD PRICES

Assumptions and Results

in Support of 1997 Fuels Report Hearing Held on August 14, 1997

(DOCKET NO. 96-FR-1)

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INTRODUCTION

Staff is presently preparing a natural gas price and supply forecast in support of the ***1997 Fuels Report***. A preliminary forecast was released to the public in April 1997 with public workshops held the following month to discuss the results. During those meetings, Staff received numerous comments, many of which have been incorporated into the revised forecast being presented in this package.

In addition to revisions to the April 1997 forecast, this package includes a preliminary end-use price forecast by sector for the three major natural gas utility service areas in California: Pacific Gas and Electric (PG&E), Southern California Gas Company (SoCalGas), and San Diego Gas and Electric (SDG&E). The end-use forecast incorporates CPUC decisions in SoCalGas' Biennial Cost Allocation (BCAP) and Performance-based Ratemaking (PBR) proceedings, as well as FERC's adoption of El Paso general rate case settlement rates. It also assumes adoption of the PG&E Gas Accord, which is expected sometime in August.

The following document includes three sections. Section I reviews modifications made to the North American Regional Gas (NARG) model since the preliminary forecast was released last April.[1] Resulting production and wellhead price projections for the U.S. and Canadian regions and an end-use forecast of natural gas prices for the three California utilities is provided in Section II. The final section provides information about the upcoming hearing to discuss the forecast and a procedural schedule for official adoption of the forecast by the Commission.

I. CHANGES MADE TO NARG MODEL ASSUMPTIONS

A. New Resource Cost Curves

Two curves were added to the NARG model and one curve was substantially modified. In the Lower 48, a cost curve was added to account for natural gas production from shale resources in the Barnett Field of central Texas. Data for the curve was obtained from the U.S. Geological Survey, the principal supplier of data used to generate the set of resource cost curves used for the Lower 48. Cost curves were also added for two areas in Canada: one in the northeastern part of British Columbia and the other off the coast of Nova Scotia (Sable Island) in eastern Canada. The data for

[1] Recall that the NARG model is the principal tool used by the Commission to generate a long-term natural gas price and supply forecast.

the Canadian resources were obtained from the Canadian National Energy Board (NEB). Each cost curve is presented below.

Permian USGS 4503 - Barnett Shale (Fort Worth Basin) Proved Reserves 0.012 TCF				
Cumulative Reserves (TCF)	Capital Cost (95$/MCF)	Operating Cost (95$/MCF)	Production Profile	Production Year
0.000	0.27	0.48	0.291	0
0.473	0.38	0.51	0.206	1
1.342	0.45	0.56	0.146	2
1.438	0.62	0.61	0.103	3
2.370	0.83	0.69	0.073	4
2.473	1.12	0.74	0.052	5
2.981	1.58	0.84	0.037	6
3.037	2.13	0.91	0.026	7
3.266	4.14	1.19	0.018	8
			0.013	9
			0.009	10
			0.007	11
			0.005	12
			0.003	13

British Columbia South Territories Proved Reserves 0.000 TCF R/P Ratio 10.0 Years		
Cumulative Reserves (TCF)	Capital Cost (95$/MCF)	Operating Cost (95$/MCF)
0.000	0.39	0.20
0.139	0.39	0.20
0.223	0.43	0.20
0.667	0.46	0.21
0.742	0.49	0.26
0.868	0.59	0.26
1.302	0.98	0.29
2.074	1.80	0.39
2.210	2.03	0.46
2.390	2.29	0.49
2.608	2.78	0.59
2.706	3.21	0.65
2.936	3.79	0.79
3.155	4.25	1.15

Eastern Canada Sable Island (Offshore) Proved Reserves 5.000 TCF R/P Ratio 20.0 Years		
Cumulative Reserves (TCF)	Capital Cost (95$/MCF)	Operating Cost (95$/MCF)
0.000	0.39	0.26
2.360	0.46	0.26
2.930	0.52	0.26
4.000	0.65	0.39
6.000	0.98	0.43
8.200	1.64	0.98
12.780	2.62	2.62

B. Proved Reserve Appreciation

As emphasized in the preliminary package, the NARG model now has the capability to account for reserve growth (or reserve appreciation) over time.[2] This capability fundamentally changes the economics of the NARG model since depletion effects, a long-standing assumption derived from Hotelling resource exhaustability theory, are minimized.. In terms of how the feature is utilized in NARG, reserve appreciation is applied by inputting a certain growth percentage estimate for each resource cost curve in the model that reflects the rate at which proved reserves and undiscovered resources grow over time. In this analysis, no growth in undiscovered resources is considered.

Given the large impact that reserve appreciation has in the NARG model, comments made by interested parties on the preliminary forecast focused on the reserve growth percentages assumed by Staff. While noting the inclusion of reserve appreciation is a major improvement to the NARG model, parties criticized Staff for assuming a constant rate of reserve growth over time. Most parties also agreed that Staff's assumed percentages were too optimistic.

Since the preliminary forecast was released, Staff retained two expert witnesses to further refine the reserve appreciation estimates in the model. One witness focused on reserve growth in Canada, designed to improve the generic one percent growth estimate Staff assumed for all of Canada. A second witness concentrated on evaluating productive capability in the Rocky Mountain and Gulf Coast regions, focusing on whether reserve growth estimates can support the levels of production generated by the NARG model in the preliminary forecast. Each witness will present the results of their analysis at the ***1997 Fuels Report*** hearing to be held on August 14, 1997. Staff has had numerous discussions with the two experts and have considered each person's analysis in the revised forecast.

Staff retained the use of the Energy Information Administration's 1989-1995 annual reports as the basis for reserve growth estimates in the current forecast. Responding to concerns of parties voicing an opinion on the preliminary forecast, Staff placed a four percent reserve growth cap on all regions in the Lower 48 and reduced reserve growth for unconventional resources (tight sands, coalbed methane, shale) from three percent to two percent. Canadian reserve growth estimates were increased to two percent in the frontier region of Alberta and 1.5 percent in the rest of Alberta. Reserve growth in other Canadian regions were reduced to 0.5 percent, except for Saskatchewan, which was kept at one percent.

Table 1 compares the reserve appreciation percentages assumed by Staff for each of the five cases. The table indicates that the Anadarko, Appalachian, Gulf Coast offshore, North Central, and Rocky Mountain regions are all affected by the four percent reserve growth cap. Staff retained zero growth for California offshore production. Retention of the no growth estimate for this area is consistent with the continued push from environmental activists to

[2] Proved reserve appreciation is defined as the additional resource expected to be added to reserves due to extension of known fields, reserve revisions, and improved recovery techniques.

halt California offshore production and a recent article stating that Chevron is seriously considering curtailing production in this region.[3]

TABLE 1
PROVED RESERVE APPRECIATION PERCENTAGE COMPARISON
(Annual Growth Rate per Year)

		Preliminary Basecase 4/97	Revised Basecase 8/97
Conventional Cost Curves			
Anadarko		4.08	4.00
Appalachia		6.63	4.00
California	Onshore	1.42	1.42
	Offshore	0.00	0.00
Gulf	Onshore - Eastern Gulf/Black Warrior	2.46	2.46
	Onshore - All Others	2.80	2.80
	Offshore - State	4.39	4.00
	Offshore - Federal	4.39	4.00
North Central		6.19	4.00
Northern Great Plains		3.94	3.94
Pacific Northwest		0.00	0.00
Permian		5.50	4.00
Rocky Mountains	Uinta-Piceance, Paradox, Snake River	6.12	4.00
	All Others	6.12	4.00
San Juan	San Juan Basin, Southwest Desert	0.84	0.84
	Raton Basin	0.84	0.84
Unconventional	Tight Sands, Coalbed Methane, Shale	3.00	2.00
Canadian Cost Curves	Alberta - Frontier	1.00	2.00
	Others	1.00	1.50
	British Columbia	1.00	0.50
	Saskatchewan	1.00	1.00
	Other Regions	1.00	0.50

Note: Staff reviewed EIA reserve growth estimates by state for the 1989-95 period. The statewide data was then aggregated into producing regions based on Staff's understanding of the location of each producing region in the model. A four percent cap was imposed on reserve growth for all regions.

Table 2 compares the amount of reserve appreciation by producing basin generated for the preliminary and revised basecases. With the four percent cap on reserve growth, the revised basecase now contains approximately 61 TCF less resource than the preliminary case in the Lower 48 through the year 2020. This reduction is offset by increased Canadian resources available to the marketplace.

As stated in the preliminary forecast, please recall that the estimates represent the amount of reserve appreciation expected by the year 2020. The volume of reserve appreciation shown in Table 2 would be considerably higher if Staff included reserve appreciation expected beyond the year 2020. This fact alone suggests that the reserve estimates provided in the analysis are conservative.

[3] See "Chevron May Shut Some Offshore Rigs," Contra Costa Times, March 12, 1997.

TABLE 2 TOTAL PROVED RESERVE APPRECIATION ESTIMATES TO 2020 Trillions of Cubic Feet	Preliminary Basecase 4/97	Revised Basecase 8/97	Change
Anadarko	54.535	52.769	-1.766
Appalachia	9.369	5.230	-4.139
California	1.334	1.334	0.000
Gulf Coast	87.266	77.878	-9.388
North Central	5.265	2.584	-2.681
Northern Great Plains	3.946	3.946	0.000
Pacific Northwest	0.000	0.000	0.000
Permian	46.605	27.013	-19.592
Rocky Mountains	31.820	16.386	-15.434
San Juan	19.702	11.739	-7.963
Total	259.842	198.879	-60.963

Through the year 2020, 199 TCF of proved reserve appreciation occurs in this case. Of the total, 126 TCF is attributed to conventional onshore reserves, 45 TCF to conventional offshore reserves, and 27 TCF to unconventional reserves.

C. Structural Enhancements to the NARG Model

Two changes were made to the NARG model since the preliminary case to better reflect the natural gas transportation network in North America. The first change focuses on the link between Eastern Canada and New England. In the preliminary forecast, a link was added to the NARG model to incorporate the development of natural gas production along the Nova Scotia coast. A pipeline corridor was originally added to allow gas from this region to flow to New England, Quebec, and the Maritime Provinces. Following the recommendations of representatives of the Canadian National Energy Board, Staff modified the pipeline corridor to ensure that only New England markets are served by gas produced in the region through a direct pipeline.

The second change incorporates an expansion of El Paso’s Havasu Crossover Facilities. El Paso recently expanded the Havasu Crossover by 180 MMCF/D to allow several producers to flow gas from the San Juan Basin to Texas using the underutilized Southern System mainline. A link was placed in the NARG model to allow gas to flow east from the San Juan Basin to Texas region via the Havasu Crossover and the southern system. A transmission rate of $0.105 per MCF was placed on this link, equal to the per unit reservation charge incurred by customers flowing gas east on the southern system.

D. Pipeline Transmission Rates

Limited changes were made to the transmission rate assumptions for the revised basecase forecast. The most significant change relates to the use of transmission rates adopted in the El Paso General Rate Case Settlement, effective July 1997.

E. Pipeline Capacities

Staff updated capacities on pipeline corridors in the Rocky Mountains and Canada to account for expansions considered imminent. In the Rockies, 462 MMCF/D was added to account for an expansion of the Trailblazer Pipeline system and the construction of the Pony Express Pipeline. Expansions were also incorporated for the Foothills/Northern Border system. On the Canadian side, Foothills was expanded by 700 MMCF/D. Northern Border from the Canadian border to Ventura, Iowa (West North Central region) was also expanded by 700 MMCF/D. From Ventura to Harper (East North Central region), the pipeline corridor was expanded by 492 MMCF/D. The above changes are all expected to be in place and operational during 1998.

II. RESULTS

This section presents Staff's revised forecast of natural gas production and prices by region for North America over the 20-year forecast horizon (1999-2019), with 1994 as the base year. It includes: 1) a basecase projection of wellhead production and prices, 2) supply and price availability at the California border, and 3) end use price estimates by customer class. Since the end-use price forecast was not included in the preliminary package, a detailed description of the methodology used to generate the forecast will be included in the section.

A. Wellhead Prices and Production

In the Lower 48, natural gas production is expected to grow from 17.2 TCF recorded in 1994 to 18.5 TCF in 1999, the first forecast year (Table 3). Between 1999 and 2019, Lower 48 production is expected to grow by 1.7 percent per year, reaching 26.1 TCF by the end of the forecast period. Canadian production will grow at a slower pace (1.2 percent per year through the year 2019) compared to the percentage increase projected for the Lower 48.

Regional breakdowns of production are also provided in Table 3. Natural gas produced in the Gulf Coast region continues to account for approximately half of Lower 48 production throughout the 1999-2019 forecast period. Rocky Mountain production emerges as the second largest source of natural gas in the Lower 48, surpassing combined production from the Permian and Anadarko Basins by the year 2019. Staff anticipates the strong growth in production in the Rocky Mountains to be driven by conventional production in the Wyoming Thrust Belt and tight sands production in the Greater Green River Basin.

In Canada, Alberta producers continues to provide the bulk of Canadian production even though strong growth on a percentage basis will be the case for British Columbia producers. With the expected startup of Sable Island production off the Nova Scotia coast, production from Eastern Canada will begin to serve the New England markets by 2004. Canadian production for all regions increases by 2.6 TCF from 1994 to 2019, with most of the additional supplies meeting new domestic demand. Canadian exports are expected to peak in 2014 at 3.6 TCF.

TABLE 3
LOWER 48 AND CANADIAN PRODUCTION
(TCF PER YEAR)
1997 Revised Base Case

Producing Region	1994	1999	2004	2009	2014	2019
LOWER 48						
Anadarko	2.890	2.589	2.365	2.182	2.027	1.700
Appalachia	0.531	0.686	1.109	1.108	1.326	1.470
California	0.311	0.379	0.386	0.429	0.430	0.415
Gulf Coast	9.243	9.400	10.307	11.648	12.948	14.138
North Central	0.186	0.538	0.606	0.666	0.707	0.729
Northern Great Plains	0.200	0.283	0.307	0.336	0.361	0.387
Pacific Northwest	0.003	0.009	0.017	0.027	0.042	0.064
Permian	1.677	1.838	1.925	1.833	1.533	1.316
Rocky Mountains	1.120	1.475	1.911	2.450	3.422	4.376
San Juan	1.074	1.340	1.757	1.613	1.606	1.520
Total: Lower 48	17.428	18.538	20.689	22.292	24.402	26.116
CANADA						
Alberta	4.034	4.955	5.427	5.822	6.115	6.436
British Columbia	0.569	0.717	0.753	0.766	0.777	0.792
Eastern Canada	0.000	0.256	0.173	0.120	0.092	0.083
Saskatchewan	0.282	0.001	0.101	0.137	0.166	0.170
Total: Canada	4.885	5.928	6.455	6.845	7.149	7.481

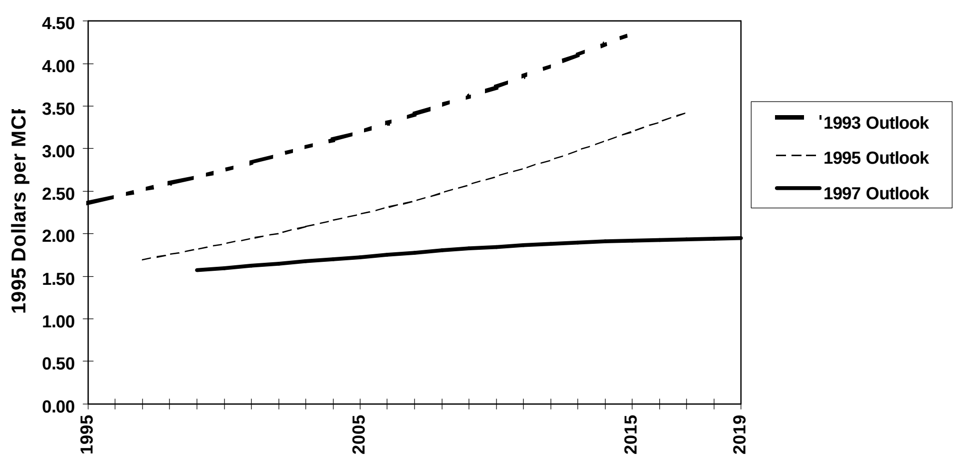
A comparison of natural gas prices by region and in the aggregate is shown in Table 4. For the Lower 48, the average price increases from $1.57 per MCF in 1999 to $1.95 per MCF in 2019, an increase of 1.1 percent per year (in 1995 dollars) on an average annual basis. The growth rate is considerably lower than previous Commission estimates, which have consistently been in the range of 3-4 percent (see Figure 2 for comparison). The sharp decline in the growth is due to two factors: 1) the use of reserve appreciation in the model for the first time, and 2) the change in the owner/producer's discount rates. Canadian wellhead prices escalate at a rate of two percent per year during the forecast period.

TABLE 4
LOWER 48 AND CANADIAN WELLHEAD PRICES
(1995$ PER MCF)

1997 Revised Base Case

Producing Region	1999	2004	2009	2014	2019
LOWER 48					
Anadarko	1.64	1.84	2.02	2.16	2.30
Appalachia	2.19	2.27	2.51	2.58	2.68
California	1.83	2.03	2.21	2.41	2.62
Gulf Coast	1.55	1.70	1.82	1.91	1.94
North Central	1.84	1.90	1.97	2.03	2.08
Northern Great Plains	1.22	1.24	1.29	1.33	1.35
Pacific Northwest	1.68	1.85	2.00	2.18	2.32
Permian	1.48	1.64	1.83	2.01	2.15
Rocky Mountains	1.45	1.41	1.43	1.47	1.51
San Juan	1.37	1.50	1.66	1.80	1.95
Total: Lower 48	1.57	1.70	1.83	1.91	1.95
CANADA					
Alberta	1.03	1.15	1.25	1.37	1.50
British Columbia	1.02	1.13	1.27	1.45	1.63
Eastern Canada	1.58	1.88	2.06	2.24	2.43
Saskatchewan	3.20	2.38	2.39	2.57	2.76
Total: Canada	1.05	1.18	1.29	1.42	1.55

Figure 1
Lower 48 Wellhead Price Forecast
1997 Natural Gas Market Outlook
Compared to 1993 and 1995 Outlooks



B. Natural Gas Supplies and Prices at the California Border

Natural gas produced in the Southwest is expected to remain the principal source of supply for California consumers during the next 20 years. After a decline from 1.013 TCF in the 1994 base year to 0.866 TCF in 1999, Southwest supplies to California increase 0.9 percent per year to 1.028 TCF in 2019. Much of this increase can be attributed to new demand in the Baja region of Northern Mexico, which will have its gas delivered through California.

While remaining the principal supplier of natural gas to the state, the market share of Southwest gas during the forecast horizon declines significantly. Rocky Mountain market share is projected to 20 percent in 2019, representing a doubling of market share over the twenty-year period. This result assumes that the Kern River system can be expanded well beyond the 1200 MMCF/D capacity Kern River officials have indicated can be implemented with compression addition. Staff projects that additional piping beyond compression needs will be needed between 2004 and 2009.

Remaining statewide natural gas requirements will be met by Canadian and in-state producers. Canadian deliveries to California will satisfy up to 30 percent of total demand with California producers providing the remainder.

Regarding estimates of border prices at Malin, Topock, or Wheeler Ridge, Staff expects prices to increase 1.7 percent per year from $1.74 per MCF in 1999 to $2.42 per MCF in the year 2019. Specific estimates of supplies and prices available to California by region appear in Table 5.

TABLE 5
CALIFORNIA BORDER SUPPLY AVAILABILITY AND PRICE

1997 Revised Base Case

Producing Region	1994	1999	2004	2009	2014	2019
Production (TCF):						
California	0.311	0.379	0.386	0.429	0.430	0.415
Southwest	1.013	0.866	1.087	0.966	1.013	1.028
Rocky Mountains	0.243	0.180	0.252	0.428	0.516	0.602
Canada	0.590	0.635	0.678	0.751	0.772	0.807
Total Supply Available to California	2.157	2.060	2.403	2.575	2.731	2.852
Price (1995$/MCF)						
California	N/A	1.83	2.03	2.21	2.41	2.62
Southwest	N/A	1.80	1.96	2.17	2.34	2.53
Rocky Mountains	N/A	1.89	1.98	2.09	2.24	2.43
Canada	N/A	1.56	1.70	1.84	2.00	2.16
Average Price at California Border	N/A	1.74	1.90	2.07	2.24	2.42

C. End-Use Price Forecast

This section provides a series of end-use natural gas price forecasts for eight end-use market sectors in the PG&E, SoCalGas and SDG&E service areas. Three of the market sectors, residential, small commercial, and some industrial customers, are classified as "core," relying entirely on natural gas to meet their fuel requirements. The other five, large commercial, most industrial, thermally enhanced oil production (TEOR), cogeneration (cogen), and utility electric generation (UEG) customers are considered "noncore," larger end-users who have other options to meet their fuel requirements.

The forecasts in this section are expressed in constant 1995 dollars per MCF and span 20 years, from 1997 to 2017. Five tables of results are provided for each utility service area. The first table provides a summary of the forecast, the second two show the detailed pricing components for each of the end-use sectors, and the fourth presents the detailed cogen and UEG price forecasts. A fifth table shows the UEG summary of fixed, variable, commodity, dispatch and total natural gas costs.

In general, the price forecasts are lower than previously published forecasts. Core prices are flat and show little variation throughout the forecast horizon. This is because of a significant reduction in transmission and distribution costs offsetting gradually increasing wellhead prices. Noncore and UEG real prices are flat initially, but turn upward after about five years into the forecast. Reductions in utility transmission and distribution costs are not large enough to offset rising wellhead prices.

A more detailed description of the forecast for each utility service area is provided in the first part of the section. Methodologies and assumptions surrounding the forecast are addressed in the final part of this section.

<u>Pacific Gas and Electric Company</u>

As the results in Table 6 suggest, the real rates of escalation for PG&E end-use prices vary in direction based on the customer class. All core rates are expected to decline during the forecast period: residential and commercial rates, down 0.5 percent per year; industrial rates, down 0.1 percent per year. In contrast, all projected noncore rates increase during the forecast. Staff expects commercial and industrial rates to increase at 0.3 percent per year with UEG rates rising 0.6 percent per year.

Figure 2 compares the 1991, 1993, and 1995 Fuels Report natural gas price forecasts for electricity generation in nominal dollars per million BTUs with the historical and the present Staff Base Case forecast. The staff forecast indicates that the downward trending historical natural gas price flatten out for the next five years or so, then gradually increase. The current forecast is lower than the 1995 Fuels Report forecast due to lower commodity prices and lower margin requirements.

The four end-use price tables for PG&E are labeled PG&E -1, -2, -3, -4 and -5 and are included at the end of the report.

TABLE 6
PG&E END-USE NATURAL GAS PRICE FORECAST SUMMARY
(1995 $/MCF)

	Core			Noncore		
Year	Residential	Commercial	Industrial	Commercial	Industrial	Electricity Generation
1997	6.23	6.25	3.87	2.62	2.62	2.34
2000	6.04	6.07	3.78	2.53	2.53	2.26
2005	5.91	5.93	3.78	2.64	2.64	2.39
2010	5.78	5.80	3.78	2.66	2.66	2.44
2017	5.69	5.70	3.83	2.79	2.79	2.61

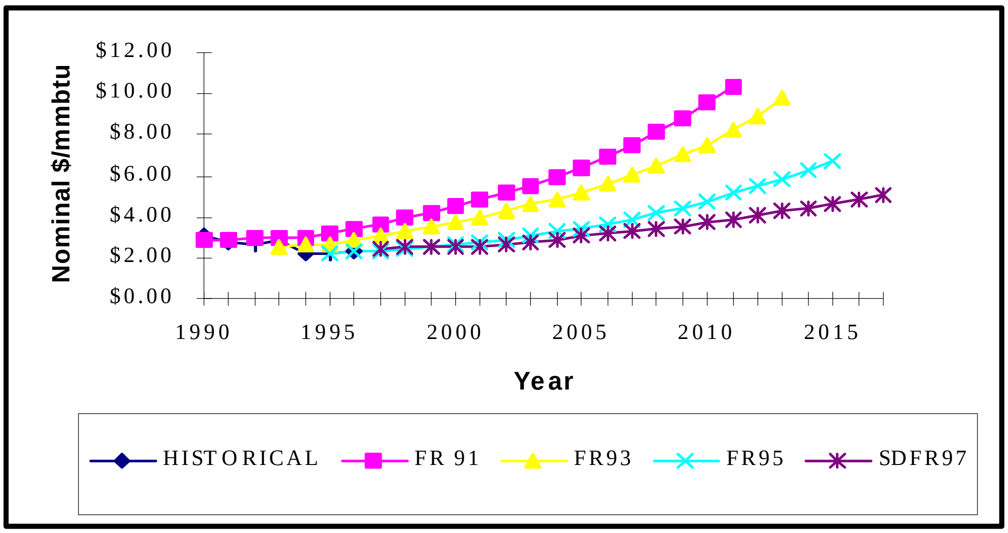


Figure 2, PG&E Historical and Forecasted UEG Gas Prices

<u>Southern California Gas Company</u>

End-use prices for core residential customers are expected to dip in real terms until about 2005, subsequently turning upward thereafter. The overall annual growth rate declines over the entire forecast period by 0.3 percent.

Core commercial and industrial customer rates follow a similar pattern, with core commercial reaching the base year 1997 forecasted price in 2017 and core industrial increasing at 0.2 percent per year. Noncore commercial and industrial are equally priced, with the prices dipping slightly prices in the early years. Overall prices increase 1.1 percent per year.

Historical and forecasted prices for cogen and utility electricity generation are shown in Figure 3. As the figure indicates, prices that are falling historically are projected to flatten out until just after the turn of the century. The annual growth rate is expected to be one percent per year during the forecast period.

TABLE 7 SOCALGAS END-USE NATURAL GAS PRICE FORECAST SUMMARY (1995 $/MCF)						
	Core			Noncore		
Year	Residential	Commercial	Industrial	Commercial	Industrial	Electricity Generation
1997	6.44	4.82	3.72	2.44	2.44	2.30
2000	6.22	4.68	3.64	2.39	2.39	2.13
2005	5.90	4.50	3.55	2.44	2.44	2.19
2010	6.08	4.68	3.74	2.68	2.68	2.43
2017	6.09	4.79	3.91	3.04	3.04	2.80

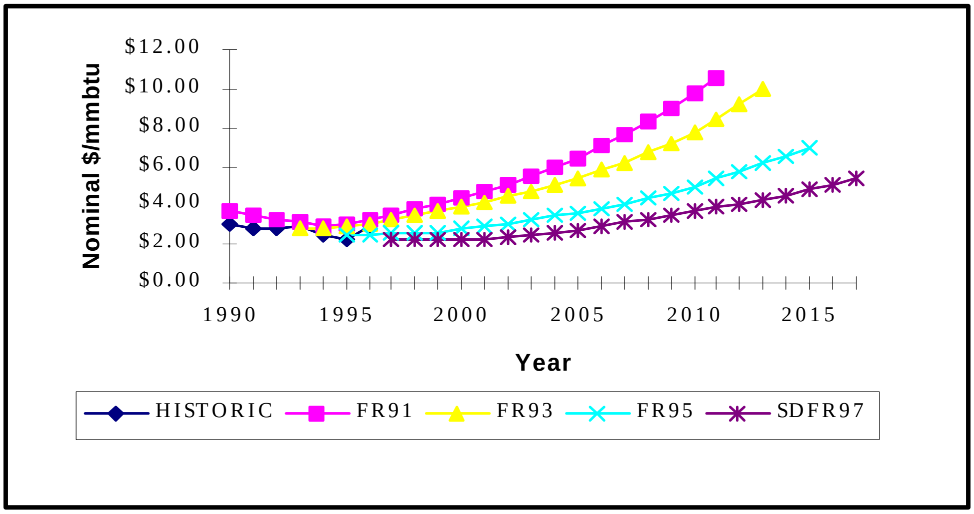


Figure 3, SCG Historical and Forecasted UEG Gas Prices

The five end-use price tables for SoCalGas are labeled SCG -1, -2, -3, -4 and -5 and are found at the end of the report.

San Diego Gas and Electric Company

The prices contained in table 8 suggest that residential prices in the SDG&E service area will fall at about 0.4 percent per year. On the other hand, core commercial and industrial have positive growth rates of 0.5 and 1.0 percent per year, respectively. The combination of increasing wellhead prices and interstate pipeline demand charges cancel out the declining allocation of margin to these sectors. Noncore commercial and industrial sectors are priced the same and grow at a positive 1.2 percent per year. These prices are flat until about 2001, before increasing.

As Figure 4 indicates, SDG&E natural gas prices for electricity generation prices have been flat for the past few years. This cycle's price forecast is similar to the one prepared for the ***1995 Fuels Report***. Prices are forecasted to remain flat until about 2000, when they begin to grow gradually. Overall, electric generation customer rates are projected to increase 1.5 percent per year over the forecast period.

TABLE 8 SDG&E END-USE NATURAL GAS PRICE FORECAST SUMMARY (1995 $/MCF)						
	Core			Noncore		
Year	Residential	Commercial	Industrial	Commercial	Industrial	Electricity Generation
1997	6.92	3.93	3.31	2.74	2.74	2.52
2000	6.80	3.98	3.40	2.74	2.74	2.59
2005	6.59	4.03	3.50	2.90	2.90	2.73
2010	6.38	4.10	3.63	3.10	3.10	2.96
2017	6.41	4.38	3.97	3.51	3.51	3.40

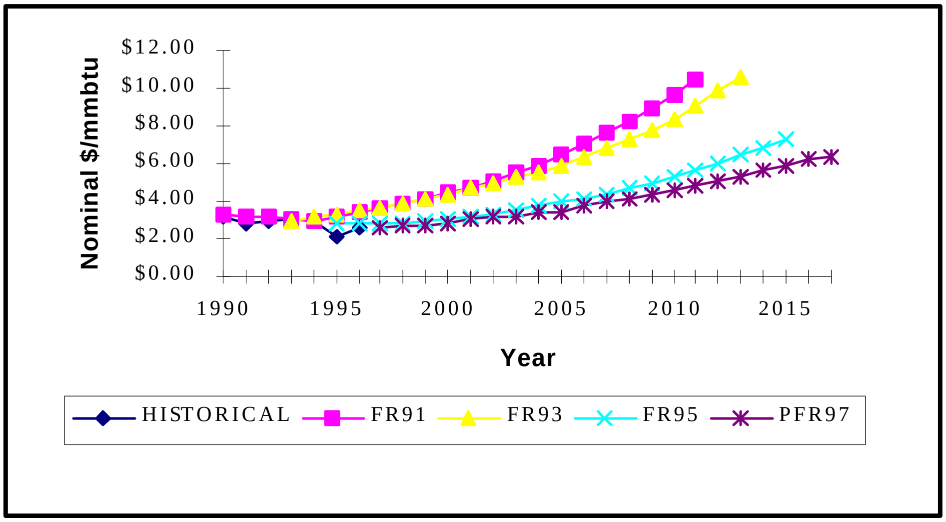


Figure 4, SDG&E Historical and Forecasted UEG Gas Prices

The five end-use price tables for SDG&E are labeled SDG&E -1, -2, -3, -4 and -5 and are found at the end of the report.

Methodology and Assumptions

Each end-use price calculated in the analysis is the sum of three components. The first two, the commodity price and transportation price forecasts for natural gas delivered into the gas utilities' system, is obtained from the NARG model results discussed previously. The third component accounts for in-state transmission, distribution and other regulatory costs, based on information obtained through discussions with utility representatives, regulatory filings made by the utilities, or CPUC decisions.

Interstate Pipeline Assumptions

Pacific Gas Transmission Company

Pacific Gas Transmission Company (PGT) delivers Canadian natural gas to California. In the early 1990s, the PGT system was expanded to increase delivery capacity to California from 1020 MMCF/D to 1775 MMCF/D. Different from past forecasts, Staff now applied a "rolled-in" rate to the PGT line, consistent with FERC directives in the pipeline's general rate case proceeding (FERC Docket RP94-149).

Firm and discounted transportation charges were totaled to cover all transportation costs between the production area in Alberta, Canada to Malin, Oregon, where the natural gas supply is received by Pacific Gas and Electric Company. A single yearly commodity price was determined for Canadian gas delivered to California, resulting from NARG base case results.

Based on PG&E's August 1996 Gas Accord[4] filing to the CPUC, it was assumed that 600 MMCF/D of firm PGT capacity would be dedicated to the core market. This requirement was assumed to extend for the full 20 year forecast period. A firm transportation cost of $0.514 per MCF was used as the total firm transportation rate from Alberta to Malin, Oregon.

Regarding the PGT Expansion project, Edison and SDG&E originally contracted for 200 MMCF/D and 52 MMCF/D, respectively, in firm capacity on the PGT system. Since negotiations recently completed with PG&E relieves Edison from its firm capacity commitment beginning in 1998, the 200 MMCF/D firm capacity reduction was factored into the end-use price forecast. For 1997, $0.514 per MCF was used as the firm transport cost. Staff assumed that SDG&E's 50 MMCF/D firm capacity commitment on PGT will be maintained, but SDG&E would be discounting the transportation costs. The discounted rates are assumed to incorporate impacts of electricity restructuring and competition from other supply sources on delivered prices to its customers.

4 PG&E, *Gas Accord, The Gas Accord Settlement Agreement* , August 9, 1996, page 17.

In the staff forecast, remaining Canadian supply is assumed to be delivered to the California border at shipper discounted transportation prices. This is consistent with present operations.

El Paso Natural Gas and Transwestern Pipeline Companies

Both the El Paso and Transwestern pipelines deliver natural gas to California from production areas located in the southwestern part of the United States. Because of their access to similar supply origins and pipeline paths, the two pipeline systems are treated as one in the Staff analysis.

Staff incorporated PG&E's assertion that it will not subscribe for any firm capacity on the El Paso system, beginning in 1998. PG&E will continue to maintain 100 MMCF/D in firm capacity on Transwestern for core needs and 50 MMCF/D for its UEG requirements. SoCalGas' Southwest firm capacity for core was assumed by Staff to be 1044 MMCF/D for the entire study period. That estimate is based on an April 1997 CPUC BCAP decision applicable to SoCalGas and SDG&E.[5]

SDG&E currently has 10 MMCF/D in firm capacity on El Paso. Staff assumed that the utility maintains this contract level throughout the forecast period, dedicated to the core market.

A firm and combined El Paso/Transwestern transportation rate of $0.364 per MCF was used, which incorporates the recent El Paso settlement rates (FERC Docket RP95-363). Remaining southwest supply is delivered to California border at discount rates.

Kern River Transmission System

California receives Rocky Mountain gas via the Kern River line. About half of the supply is delivered into the California utility systems, with the rest delivered directly to end-users. Transport costs on the Kern River system are discounted.

Mojave Pipeline Company

Mojave Pipeline receives gas from El Paso and Transwestern at the California border and transports it into California, principally to meet TEOR customer demand. Transportation costs to deliver the supply to the Mojave system are included in the El Paso and Transwestern combined system. Transport costs on Mojave are discounted.

Supply Allocation to Core and Noncore

Once each utility's supply was identified from the interstate pipelines, it was separated into two parts, firm and nonfirm supply. The firm supplies and associated commodity and

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5 CPUC, Decision 97-04-082, April 23, 1997.

transport costs were assigned to their respective market sectors. These include core customers and utility electricity generation (UEG). The firm supplies to each were separately totaled and an interstate weighted average firm transportation and commodity price was calculated.

In summary, PG&E core firm capacity includes 600 MMCF/D from PGT and 100 MMCF/D from Transwestern. In addition, the core has access to 50 MMCF/D from California production. PG&E electric generation has 50 MMCF/D in firm capacity on Transwestern.

SoCalGas core firm capacity includes 1044 MMCF/D from El Paso and Transwestern. After adjusting Southern California production for non-utility and TEOR direct deliveries, 75 percent of the remaining production is assumed to be used to meet core needs.

SCE has no firm capacity after 1998. SDG&E continues to hold 50 MMCF/D in firm capacity from Canada and 10 MMCF/D from the southwest.

Remaining supply for each pipeline is placed in a noncore supply pool for each utility service area. Noncore supply is summed and a weighted average discounted interstate transportation and commodity price is determined. Any shortfall in firm supply is augmented by incremental supplies from the noncore supply pool.

Instate Transmission and Distribution Costs

Each utility has margin revenue projections required to cover administration, system operation, taxes and a CPUC-adopted profit level from their system. Utility representatives provided their own forecasted margin requirements or otherwise sufficient information to Staff in order to prepare a margin forecast. A portion of the margin requirement was assigned to each of the eight customer sectors. This allocation is based on either recent CPUC decisions or utility filings.

Specifically, factors were calculated for allocating the margin to core and noncore classes. Next, a second set of factors was determined to allocate the core and noncore shares of the margin to each end-use customer class. The core, noncore and end-use class allocation factors shift as demand changes over time.

Each year’s allocation factors are multiplied by the forecasted margin requirement, providing an estimate for margin share to be collected from each of the end-use sectors. Each revenue stream is then divided by the appropriate throughput for that sector and year to obtain a unit transmission and distribution cost, called Fixed Margin, expressed in $/MCF.

A new in-state cost category, “Other Regulatory,” has been added to the forecast to account for social programs and balancing accounts assumed to exist through the 20-year period. Estimates for this cost from the base year 1997 are held constant in 1995$ for succeeding years. A brief explanation of the assumptions and methodologies used to determine the margin and the allocation factors for the three gas utilities follows.

Pacific Gas and Electric Company

PG&E's Gas Accord Settlement provides the basis for Staff's natural gas price forecast for the PG&E service area. Additionally, the Gas Accord documents used for the forecast was prepared almost a year ago. Since then, PG&E has been holding discussions with its customers, results of which could also have an impact on the forecast. This forecast, then, is susceptible to some modification in assumptions due to both CPUC decision implementation and the continuing negotiations by PG&E.

Because of preparations for its general rate case to be filed by the end of this year, PG&E was unable to provide a margin requirement forecast. Instead, the utility provided its gas department's results of operation, rate base, and calculated rate of return for the years 1995 and 1996. The revenues were then adjusted to reflect PG&E's recovery of its full authorized rate of return for these years. These two years were then averaged to obtain an average 1996 revenue requirement of $1,565 million (1995 dollars). Based on the ***1995 Fuels Report*** natural gas price forecast,[6] annual escalation rates were calculated and applied to the 1996 revenue requirement to obtain a forecasted 20 year margin requirement for PG&E.

In the Gas Accord, certain transportation costs have been unbundled so that the revenue needs would be collected through volumetric use, rather than by margin allocation. These include transport costs on Lines 300, 400, and 401 and gathering costs, each incorporated in this forecast. For 1997, an overall backbone revenue requirement of $201.5 million ($193.9 million in 1995 dollars) was determined from the Gas Accord settlement[7].

Base year backbone revenues were escalated for the forecast period using the same factors applied to the margin revenue needs. The backbone revenues were then subtracted from the margin requirements. An adjusted margin requirement was thus estimated, to which the allocation factors are applied. Table A-4 (at the end of this document shows the backbone revenue estimate and the adjusted margin requirement.

Staff assumed that PG&E will be at risk to recover these backbone transportation revenues. A single unit charge for each pipeline segment was determined from the Gas Accord and applied to the respective noncore flows. These unit charges were held constant for all future years. In the price tables, the weighted average for these is referenced as "Backbone Charges."

The PG&E's Gas Accord was also used to develop margin allocation factors. The factors are based on the summary of PG&E's six unbundled margin requirements for 1997. The following table provides the summary.

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6 See CEC, *Natural Gas Market Outlook*, Appendix F, October 1995, Page F-3.

7 See PG&E, Gas Accord, Workpapers for the Gas Accord Settlement Agreement, August 20, 1996, Chapter 18.

The sector terms used by PG&E, such as small and large commercial, are not consistent with the Energy Commission demand forecast used in calculating unit sectoral rates. For the purposes of determining allocation factors, it is assumed that small commercial is core commercial, large commercial is core industrial, distribution is noncore commercial, and transmission is noncore industrial.

TABLE 9
SUMMARY OF PG&E MARGIN REQUIREMENTS
FOR 1997

Millions of 1997 Dollars

Sector	Yearly Thruput mmbtu	Margin Distr	Customer Class	Access Charge	Core Backbone	Local Transm	Storage	Total
Residential	2,076.9	526.1	73.2	0.0	30.7	53.0	33.5	716.5
Sml Commercial	781.9	198.0	31.6	0.0	11.6	20.0	10.6	271.8
Lrg Commercial	158.4	15.0	4.8	0.0	2.1	3.6	1.9	27.3
Distribution	413.8	27.1	8.6	0.0	0.0	6.5	0.0	42.2
Transmission	1,238.0	0.0	21.5	35.9	0.0	15.8	0.0	73.3
UEG	1,910.1	0.0	25.3	13.6	0.0	24.3	0.0	63.1
Cogen	924.4	0.9	12.2	6.6	0.0	11.8	0.0	31.5
Coalinga	2.2	0.0	0.0	0.1	0.0	0.1	0.0	0.2
Palo Alto	36.9	0.0	0.5	0.5	0.0	1.0	0.0	1.9
Total	7,542.5	767.1	177.7	56.6	44.4	136.0	46.0	1,227.8

Source: PG&E, *Gas Accord, Workpapers for the Gas Accord Settlement Agreement* , August 20, 1996.

To compute allocations factors for the core and noncore class, revenues were summed for the sectors in each class and divided by the total revenue requirement. Individual end-use sector allocation factors were determined by dividing each sector by its core or noncore revenue allocation. (See Table A-1)

Another feature of the Gas Accord is the phase-in of Lines 400 and 401. Staff assumed the annual phase-in would continue at the rate of 25 MMCF/D after 2002. Line 400 rates were held constant at $0.109 per MCF with Line 401 held at $0.233 per MCF. Off-system Line 401 transport costs for natural gas supply delivery to southern California was assumed to be $0.337 per MCF in 1997, dropping to $0.296 per MCF in 2002, and held constant for the rest of the forecast.

PG&E's BCAP[8] filing formed the basis for determining the "Other Regulatory" charge (See Table B-1).

Southern California Gas Company

8 PG&E, *Biennial Cost Allocation Proceeding, (Gas), Prepared Testimony* , CPUC Docket A.97-03-002, March 3, 1997.

A margin requirement estimate was provided by SoCalGas for 1997 through 2006. This estimate is based on SoCalGas' "as filed" Performance Based Regulation (PBR) application [9]. The margin forecast was converted to 1995 dollars. To calculate margin requirements for the remaining ten years, annual escalation factors were first determined from the last Fuels Report for the period 2007 through to 2017. These were then applied to the 2005 margin requirement, which computes a margin need through to 2017. (See Table A-4)

Allocation factors were determined using the recent BCAP decision. Table A-2 provides the revenue and throughput information used to determine the allocation factors.

In applying the resulting factors, the utility's G-10 rate classification was assumed to be core commercial and G-20 to be core industrial. G-30 was split into noncore commercial and industrial using the 1996 California Gas Report. The "Other Regulatory" charge was determined form the BCAP decision and held constant for all years. See Table B-2 for the specific revenues included in this charge.

<u>San Diego Gas and Electric Company</u>

Margin forecasts through 2010 was provided by SDG&E in nominal dollars, [10] based on the April 1997 combined SoCalGas and SDG&E BCAP decision. The forecast was converted to 1995 dollars. Projections between 2011 and 2017 were estimated using the same procedures employed for the other utility estimates. Table A-3 contains the SDG&E margin forecast used in this analysis.

The BCAP decision was used to determine SDG&E's margin allocation factors Table A-3 provides the throughputs and revenues used to compute the factors. In applying the factors, SDG&E's large commercial sector was assumed to be core industrial. Noncore commercial/industrial was divided equally between the noncore commercial and industrial sectors.

Allocation factors and "Other Regulatory" charges were determined based on the BCAP Decision. See Table B-3 for the specific revenues included in this charge.

III. NEXT STEPS

The Fuels and Transportation Committee will hold a hearing on August 14, 1997 to discuss Staff's revised natural gas price and supply forecast. The hearing will be held in Hearing

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9 The CPUC issued a decision on SoCalGas' PBR on July 16, 1997 which reduces SoCalGas' margin requirement by about $160 million. It is uncertain to what extent this decision will impact the various rate classes.

10 The CPUC decision on SoCalGas' PBR could also impact the SDG&E revenue requirement.

Room A at the California Energy Commission in Sacramento. In preparation for that meeting, the Committee is requesting comments about the forecast from interested parties.

Your comments will be accepted in any format you would like. Please contact the following people if you have any questions about the forecast:

Jairam Gopal	(916) 654-4880	jgopal@energy.state.ca.us
Scott Tomashefsky	(916) 654-4896	stomashe@energy.state.ca.us
Bill Wood	(916) 654-4882	bwood@energy.state.ca.us

If you wish to mail your comments, please do so to any of the above people by August 13 at the following address:

California Energy Commission
Fuel Resources Office
1516 Ninth Street, MS-23
Sacramento, CA 95814

Table PG&E -1

Pacific Gas & Electric Company

1997 Fuels Report

Staff Base Case

End-use Natural Gas Price Forecast by Sector

1995 $ per mcf

	Core			Noncore					System
Year	**Res**	**Comm**	**Indust**	**Comm**	**Indust**	**TEOR**	**Cogen**	**UEG**	**Average**
1989	6.33	6.08	5.81	3.47	3.46	2.71	3.52	3.52	4.23
1990	6.42	6.33	5.59	3.63	3.94	2.93	3.65	3.65	4.40
1991	6.44	6.44	5.64	2.99	3.14	3.47	3.15	3.15	4.25
1992	6.20	6.77	5.04	2.89	2.31	2.72	2.87	2.87	4.51
1993	5.92	6.28	4.97	3.10	2.30	2.43	3.10	3.10	3.69
1994	6.11	6.32	4.65	3.02	2.06	2.05	2.32	2.32	3.62
1995	6.35	6.41	4.67	2.52	1.85	1.52	2.24	2.24	3.57
1996	6.29	6.33	4.27	2.57	2.24	1.77	2.36	2.36	3.87
1997	6.23	6.25	3.87	2.62	2.62	2.02	2.34	2.34	3.66
1998	6.20	6.22	3.86	2.67	2.67	1.99	2.39	2.39	3.68
1999	6.14	6.17	3.83	2.65	2.65	1.98	2.38	2.38	3.65
2000	6.04	6.07	3.78	2.54	2.53	2.01	2.26	2.26	3.51
2001	6.01	6.03	3.77	2.55	2.55	2.03	2.28	2.28	3.52
2002	5.98	6.00	3.77	2.57	2.57	2.05	2.29	2.29	3.51
2003	5.94	5.97	3.77	2.59	2.59	2.08	2.32	2.32	3.50
2004	5.94	5.96	3.78	2.61	2.61	2.09	2.36	2.36	3.54
2005	5.91	5.93	3.78	2.64	2.64	2.12	2.39	2.39	3.54
2006	5.87	5.89	3.78	2.63	2.63	2.12	2.39	2.39	3.49
2007	5.85	5.87	3.77	2.65	2.65	2.12	2.39	2.39	3.50
2008	5.79	5.81	3.75	2.66	2.66	2.12	2.41	2.41	3.48
2009	5.79	5.81	3.77	2.64	2.64	2.08	2.42	2.42	3.46
2010	5.78	5.80	3.78	2.66	2.66	2.09	2.44	2.44	3.48
2011	5.77	5.79	3.78	2.68	2.68	2.10	2.47	2.47	3.49
2012	5.74	5.76	3.78	2.70	2.70	2.09	2.48	2.48	3.47
2013	5.74	5.76	3.80	2.72	2.72	2.11	2.50	2.50	3.51
2014	5.71	5.73	3.80	2.72	2.72	2.14	2.54	2.54	3.50
2015	5.69	5.71	3.80	2.74	2.74	2.15	2.56	2.56	3.50
2016	5.69	5.70	3.82	2.76	2.76	2.16	2.59	2.59	3.51
2017	5.69	5.70	3.83	2.79	2.79	2.18	2.61	2.61	5.51

Note: * 1989 - 1995 prices are historical for residential, commercial, industrial, and TEOR;
prices between 1995 and 1997 are interpolated.
* 1989 - 1996 prices are historical for cogeneration and UEG,
* 1997 and later years are forecasted.

July 25, 1997

Table PG&E -2

Pacific Gas & Electric Company

1997 Fuels Report

Staff Base Case

Core End-use Natural Gas Price Forecast by Sector

1995 $ per mcf

Residential Core Price

Year	Fixed	PG&E Backbone	Pipe Dmd Charge	ITCS	Other Regulatory	Commodity	Total
1989							6.33
1990							6.42
1991							6.44
1992							6.20
1993							5.92
1994							6.11
1995							6.35
1996							6.29
1997	3.85	0.12	0.46	0.04	0.49	1.28	6.23
1998	3.82	0.12	0.46	0.04	0.49	1.27	6.20
1999	3.76	0.12	0.47	0.04	0.49	1.27	6.14
2000	3.67	0.12	0.47	0.00	0.49	1.30	6.04
2001	3.62	0.12	0.47	0.00	0.49	1.33	6.01
2002	3.55	0.12	0.46	0.00	0.49	1.36	5.98
2003	3.49	0.12	0.46	0.00	0.49	1.38	5.94
2004	3.47	0.12	0.46	0.00	0.49	1.41	5.94
2005	3.41	0.12	0.46	0.00	0.49	1.44	5.91
2006	3.33	0.12	0.46	0.00	0.49	1.48	5.87
2007	3.31	0.12	0.46	0.00	0.49	1.48	5.85
2008	3.22	0.12	0.46	0.00	0.49	1.51	5.79
2009	3.20	0.12	0.46	0.00	0.49	1.53	5.79
2010	3.16	0.12	0.46	0.00	0.49	1.56	5.78
2011	3.12	0.12	0.46	0.00	0.49	1.59	5.77
2012	3.06	0.12	0.46	0.00	0.49	1.62	5.74
2013	3.04	0.12	0.46	0.00	0.49	1.64	5.74
2014	2.97	0.12	0.46	0.00	0.49	1.68	5.71
2015	2.92	0.12	0.46	0.00	0.49	1.70	5.69
2016	2.89	0.12	0.46	0.00	0.49	1.73	5.69
2017	2.86	0.12	0.46	0.00	0.49	1.76	5.69

Commercial Core Price

Year	Fixed	PG&E Backbone	Pipe Dmd Charge	ITCS	Other Regulatory	Commodity	Total
1989							6.08
1990							6.33
1991							6.44
1992							6.77
1993							6.28
1994							6.32
1995							6.41
1996							6.33
1997	3.88	0.12	0.46	0.04	0.48	1.28	6.25
1998	3.85	0.12	0.46	0.04	0.48	1.27	6.22
1999	3.79	0.12	0.47	0.04	0.48	1.27	6.17
2000	3.70	0.12	0.47	0.00	0.48	1.30	6.07
2001	3.65	0.12	0.47	0.00	0.48	1.33	6.03
2002	3.58	0.12	0.46	0.00	0.48	1.36	6.00
2003	3.52	0.12	0.46	0.00	0.48	1.38	5.97
2004	3.49	0.12	0.46	0.00	0.48	1.41	5.96
2005	3.44	0.12	0.46	0.00	0.48	1.44	5.93
2006	3.35	0.12	0.46	0.00	0.48	1.48	5.89
2007	3.33	0.12	0.46	0.00	0.48	1.48	5.87
2008	3.25	0.12	0.46	0.00	0.48	1.51	5.81
2009	3.22	0.12	0.46	0.00	0.48	1.53	5.81
2010	3.18	0.12	0.46	0.00	0.48	1.56	5.80
2011	3.14	0.12	0.46	0.00	0.48	1.59	5.79
2012	3.08	0.12	0.46	0.00	0.48	1.62	5.76
2013	3.06	0.12	0.46	0.00	0.48	1.64	5.76
2014	3.00	0.12	0.46	0.00	0.48	1.68	5.73
2015	2.95	0.12	0.46	0.00	0.48	1.70	5.71
2016	2.92	0.12	0.46	0.00	0.48	1.73	5.70
2017	2.89	0.12	0.46	0.00	0.48	1.76	5.70

Industrial Core Price

Year	Fixed	PG&E Backbone	Pipe Dmd Charge	ITCS	Other Regulatory	Commodity	Total
1989							5.81
1990							5.59
1991							5.64
1992							5.04
1993							4.97
1994							4.65
1995							4.67
1996							4.27
1997	1.90	0.12	0.46	0.04	0.08	1.28	3.87
1998	1.89	0.12	0.46	0.04	0.08	1.27	3.86
1999	1.86	0.12	0.47	0.04	0.08	1.27	3.83
2000	1.82	0.12	0.47	0.00	0.08	1.30	3.78
2001	1.79	0.12	0.47	0.00	0.08	1.33	3.77
2002	1.76	0.12	0.46	0.00	0.08	1.36	3.77
2003	1.73	0.12	0.46	0.00	0.08	1.38	3.77
2004	1.71	0.12	0.46	0.00	0.08	1.41	3.78
2005	1.69	0.12	0.46	0.00	0.08	1.44	3.78
2006	1.65	0.12	0.46	0.00	0.08	1.48	3.78
2007	1.63	0.12	0.46	0.00	0.08	1.48	3.77
2008	1.59	0.12	0.46	0.00	0.08	1.51	3.75
2009	1.58	0.12	0.46	0.00	0.08	1.53	3.77
2010	1.56	0.12	0.46	0.00	0.08	1.56	3.78
2011	1.54	0.12	0.46	0.00	0.08	1.59	3.78
2012	1.51	0.12	0.46	0.00	0.08	1.62	3.78
2013	1.50	0.12	0.46	0.00	0.08	1.64	3.80
2014	1.47	0.12	0.46	0.00	0.08	1.68	3.80
2015	1.45	0.12	0.46	0.00	0.08	1.70	3.80
2016	1.43	0.12	0.46	0.00	0.08	1.73	3.82
2017	1.42	0.12	0.46	0.00	0.08	1.76	3.83

Note: 1989 - 1995 total prices are historical, obtained from QFER Form 7. Prices between 1995 and 1997 are interpolated.
ITCS are interim transportation charges resultant from the implementation of FERC Order 636.

July 25, 1997

Table PG&E -3

Pacific Gas & Electric Company

1997 Fuels Report

Staff Base Case

NonCore End-Use Natural Gas Price Forecast by Sector

1995 $ per mcf

Commercial Noncore Price

Year	PG&E Fixed	PG&E Backbone	Pipe Dmd Charge	ITCS	Other Regulatory	Commodity	Total
1989							3.47
1990							3.63
1991							2.99
1992							2.89
1993							3.10
1994							3.02
1995							2.52
1996							2.57
1997	0.76	0.14	0.28	0.10	0.08	1.26	2.62
1998	0.75	0.15	0.32	0.14	0.08	1.24	2.67
1999	0.74	0.16	0.29	0.14	0.08	1.24	2.65
2000	0.74	0.15	0.29	0.00	0.08	1.27	2.54
2001	0.72	0.15	0.30	0.00	0.08	1.30	2.55
2002	0.71	0.14	0.30	0.00	0.08	1.34	2.57
2003	0.70	0.14	0.30	0.00	0.08	1.37	2.59
2004	0.69	0.15	0.29	0.00	0.08	1.40	2.61
2005	0.69	0.15	0.29	0.00	0.08	1.44	2.64
2006	0.68	0.15	0.29	0.00	0.08	1.44	2.63
2007	0.67	0.13	0.32	0.00	0.08	1.45	2.65
2008	0.65	0.13	0.32	0.00	0.08	1.47	2.66
2009	0.65	0.15	0.33	0.00	0.08	1.42	2.64
2010	0.64	0.15	0.34	0.00	0.08	1.45	2.66
2011	0.63	0.15	0.35	0.00	0.08	1.47	2.68
2012	0.62	0.13	0.40	0.00	0.08	1.46	2.70
2013	0.62	0.14	0.40	0.00	0.08	1.49	2.72
2014	0.59	0.15	0.36	0.00	0.08	1.54	2.72
2015	0.59	0.15	0.36	0.00	0.08	1.56	2.74
2016	0.58	0.15	0.37	0.00	0.08	1.59	2.76
2017	0.57	0.15	0.37	0.00	0.08	1.61	2.79

Industrial Noncore Price

Year	PG&E Fixed	PG&E Backbone	Pipe Dmd Charge	ITCS	Other Regulatory	Commodity	Total
1989							3.46
1990							3.94
1991							3.14
1992							2.31
1993							2.30
1994							2.06
1995							1.85
1996							2.24
1997	0.76	0.14	0.28	0.10	0.08	1.26	2.62
1998	0.75	0.15	0.32	0.14	0.08	1.24	2.67
1999	0.74	0.16	0.29	0.14	0.08	1.24	2.65
2000	0.74	0.15	0.29	0.00	0.08	1.27	2.53
2001	0.72	0.15	0.30	0.00	0.08	1.30	2.55
2002	0.71	0.14	0.30	0.00	0.08	1.34	2.57
2003	0.70	0.14	0.30	0.00	0.08	1.37	2.59
2004	0.69	0.15	0.29	0.00	0.08	1.40	2.61
2005	0.69	0.15	0.29	0.00	0.08	1.44	2.64
2006	0.68	0.15	0.29	0.00	0.08	1.44	2.63
2007	0.67	0.13	0.32	0.00	0.08	1.45	2.65
2008	0.65	0.13	0.32	0.00	0.08	1.47	2.66
2009	0.65	0.15	0.33	0.00	0.08	1.42	2.64
2010	0.64	0.15	0.34	0.00	0.08	1.45	2.66
2011	0.63	0.15	0.35	0.00	0.08	1.47	2.68
2012	0.62	0.13	0.40	0.00	0.08	1.46	2.70
2013	0.62	0.14	0.40	0.00	0.08	1.49	2.72
2014	0.59	0.15	0.36	0.00	0.08	1.54	2.72
2015	0.58	0.15	0.36	0.00	0.08	1.56	2.74
2016	0.58	0.15	0.37	0.00	0.08	1.59	2.76
2017	0.57	0.15	0.37	0.00	0.08	1.61	2.79

TEOR Noncore Price

Year	PG&E Fixed	PG&E Backbone	Pipe Dmd Charge	ITCS	Other Regulatory	Commodity	Total
1989							2.71
1990							2.93
1991							3.47
1992							2.72
1993							2.43
1994							2.05
1995							1.52
1996							1.77
1997	0.76	0.00	0.00	0.00	0.00	1.26	2.02
1998	0.75	0.00	0.00	0.00	0.00	1.24	1.99
1999	0.74	0.00	0.00	0.00	0.00	1.24	1.98
2000	0.74	0.00	0.00	0.00	0.00	1.27	2.01
2001	0.72	0.00	0.00	0.00	0.00	1.30	2.03
2002	0.71	0.00	0.00	0.00	0.00	1.34	2.05
2003	0.70	0.00	0.00	0.00	0.00	1.37	2.08
2004	0.69	0.00	0.00	0.00	0.00	1.40	2.09
2005	0.69	0.00	0.00	0.00	0.00	1.44	2.12
2006	0.68	0.00	0.00	0.00	0.00	1.44	2.12
2007	0.67	0.00	0.00	0.00	0.00	1.45	2.12
2008	0.65	0.00	0.00	0.00	0.00	1.47	2.12
2009	0.65	0.00	0.00	0.00	0.00	1.42	2.08
2010	0.64	0.00	0.00	0.00	0.00	1.45	2.09
2011	0.63	0.00	0.00	0.00	0.00	1.47	2.10
2012	0.62	0.00	0.00	0.00	0.00	1.46	2.09
2013	0.62	0.00	0.00	0.00	0.00	1.49	2.11
2014	0.59	0.00	0.00	0.00	0.00	1.54	2.14
2015	0.58	0.00	0.00	0.00	0.00	1.56	2.15
2016	0.58	0.00	0.00	0.00	0.00	1.59	2.16
2017	0.57	0.00	0.00	0.00	0.00	1.61	2.18

Note: 1989 - 1995 total prices are historical, obtained from QFER Form 7. Prices between 1995 and 1997 are interpolated.
ITCS are interim transportation charges resultant from the implementation of FERC Order 636.

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Table PG&E -4
Pacific Gas & Electric Company
1997 Fuels Report
Staff Base Case
Electricity Generation Natural Gas Price Forecast

1995 $ per mcf

Cogen Noncore Price

	PG&E		Pipe Dmd		Other		
Year	**Fixed**	**Backbone**	**Charge**	**ITCS**	**Regulatory**	**Commodity**	**Total**
1989							3.52
1990							3.65
1991							3.15
1992							2.87
1993							3.10
1994							2.32
1995							2.24
1996							2.36
1997	0.36	0.14	0.42	0.10	0.03	1.28	2.34
1998	0.35	0.15	0.45	0.14	0.03	1.26	2.39
1999	0.35	0.16	0.44	0.14	0.03	1.26	2.38
2000	0.34	0.15	0.44	0.00	0.03	1.29	2.26
2001	0.34	0.15	0.44	0.00	0.03	1.32	2.28
2002	0.33	0.14	0.43	0.00	0.03	1.36	2.29
2003	0.33	0.14	0.42	0.00	0.03	1.39	2.32
2004	0.32	0.15	0.43	0.00	0.03	1.42	2.36
2005	0.32	0.15	0.43	0.00	0.03	1.46	2.39
2006	0.32	0.15	0.43	0.00	0.03	1.46	2.39
2007	0.32	0.13	0.44	0.00	0.03	1.47	2.39
2008	0.31	0.13	0.45	0.00	0.03	1.49	2.41
2009	0.31	0.15	0.47	0.00	0.03	1.45	2.42
2010	0.30	0.15	0.48	0.00	0.03	1.47	2.44
2011	0.30	0.15	0.49	0.00	0.03	1.50	2.47
2012	0.30	0.13	0.52	0.00	0.03	1.49	2.48
2013	0.29	0.14	0.52	0.00	0.03	1.52	2.50
2014	0.28	0.15	0.50	0.00	0.03	1.57	2.54
2015	0.28	0.15	0.50	0.00	0.03	1.59	2.56
2016	0.27	0.15	0.51	0.00	0.03	1.62	2.59
2017	0.27	0.15	0.52	0.00	0.03	1.64	2.61

UEG Noncore Price

	Total	Fixed		Variable	Pipeline		Other		
Year	**Margin**	**Margin**	**Backbone**	**Margin**	**Demand**	**ITCS**	**Regulatory**	**Commodity**	**Total**
1989									3.52
1990									3.65
1991									3.15
1992									2.87
1993									3.10
1994									2.32
1995									2.24
1996									2.36
1997	0.36	0.31	0.14	0.05	0.42	0.10	0.03	1.28	2.34
1998	0.35	0.30	0.15	0.05	0.45	0.14	0.03	1.26	2.39
1999	0.35	0.30	0.16	0.05	0.44	0.14	0.03	1.26	2.38
2000	0.34	0.29	0.15	0.05	0.44	0.00	0.03	1.29	2.26
2001	0.34	0.28	0.15	0.05	0.44	0.00	0.03	1.32	2.28
2002	0.33	0.28	0.14	0.05	0.43	0.00	0.03	1.36	2.29
2003	0.33	0.28	0.14	0.05	0.42	0.00	0.03	1.39	2.32
2004	0.32	0.27	0.15	0.05	0.43	0.00	0.03	1.42	2.36
2005	0.32	0.27	0.15	0.05	0.43	0.00	0.03	1.46	2.39
2006	0.32	0.26	0.15	0.05	0.43	0.00	0.03	1.46	2.39
2007	0.32	0.26	0.13	0.05	0.44	0.00	0.03	1.47	2.39
2008	0.31	0.25	0.13	0.05	0.45	0.00	0.03	1.49	2.41
2009	0.31	0.25	0.15	0.05	0.47	0.00	0.03	1.45	2.42
2010	0.30	0.25	0.15	0.05	0.48	0.00	0.03	1.47	2.44
2011	0.30	0.24	0.15	0.05	0.49	0.00	0.03	1.50	2.47
2012	0.30	0.24	0.13	0.05	0.52	0.00	0.03	1.49	2.48
2013	0.29	0.24	0.14	0.05	0.52	0.00	0.03	1.52	2.50
2014	0.28	0.23	0.15	0.05	0.50	0.00	0.03	1.57	2.54
2015	0.28	0.22	0.15	0.05	0.50	0.00	0.03	1.59	2.56
2016	0.27	0.22	0.15	0.05	0.51	0.00	0.03	1.62	2.59
2017	0.27	0.22	0.15	0.05	0.52	0.00	0.03	1.64	2.61

Notes: 1989-1996 prices are historical, obtained from UMFOR
ITCS are interim transportation charges resultant from the implementation of FERC Order 636.

Table PG&E -5
Pacific Gas & Electric Service Area
ER98/FR97
Staff Base Case
Electricity Generation Gas Price Forecast

1995 $ per mmBtu

	Utility Electric Generation				
Year	**Fixed Price**	**Variable Price**	**Commodity Price**	**Dispatch Price**	**Total Price**
1989				2.90	3.26
1990				2.85	3.37
1991				2.41	2.93
1992				2.11	2.66
1993				2.23	2.88
1994				1.51	2.16
1995				1.55	2.20
1996				1.60	2.25
1997	0.71	0.33	1.26	1.58	2.29
1998	0.74	0.37	1.24	1.61	2.34
1999	0.72	0.38	1.24	1.61	2.33
2000	0.72	0.24	1.27	1.50	2.22
2001	0.71	0.23	1.30	1.53	2.24
2002	0.69	0.22	1.33	1.55	2.25
2003	0.69	0.22	1.36	1.58	2.27
2004	0.69	0.24	1.39	1.62	2.31
2005	0.68	0.23	1.43	1.66	2.34
2006	0.68	0.23	1.43	1.66	2.34
2007	0.69	0.21	1.44	1.66	2.35
2008	0.69	0.22	1.46	1.68	2.37
2009	0.72	0.24	1.42	1.66	2.37
2010	0.72	0.24	1.44	1.68	2.40
2011	0.72	0.23	1.47	1.70	2.42
2012	0.75	0.21	1.46	1.68	2.43
2013	0.74	0.22	1.49	1.71	2.45
2014	0.71	0.24	1.54	1.78	2.49
2015	0.71	0.24	1.56	1.80	2.51
2016	0.72	0.24	1.59	1.82	2.54
2017	0.72	0.24	1.61	1.85	2.56

Notes:
* 1989 - 1996 total price are historic taken from PG&E's UMFOR.
* Historical dispatch prices are estimates.
* 1992 - 1994 dispatch prices are based on QFER Form 6.
* Forecasted fixed and variable costs are based on PG&E Gas Accord Settlement filing Aug. 20, 1996.
* Fixed includes utility and interstate pipeline fixed costs.
* Variable includes all costs except fixed and commodity.
* ITCS based on PG&E BCAP Application A-97-03-002.
* Commodity price = California Border price less interstate transport cost.
* Assumed 1020 btu per cf for forecasted prices.
* Inflation based on 1995=100 using Apr 16, 1997 deflators.
* Resource plan based on ER96.
* May not sum due to rounding.

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Table A-1

Pacific Gas & Electric Margin Distribution Cost Summary

1997 Summary

Pacific Gas & Electric Gas Accord Filing

	Volume mmcfd	Volume bcf	Revenue $mm	Unit Charge $/mcf	Revenue Allocation	
Core						
Residential	558	203.6	$ 716.5	$ 3.519	70.55%	0.70549
Small Commercial	210	76.7	$ 271.8	$ 3.546	26.76%	0.26763
Large Commercial	43	15.5	$ 27.3	$ 1.758	2.69%	0.02688
Core Total	810	295.8	$ 1,015.6	$ 3.433	82.71%	0.82712
Noncore						
Transmission	333	121.4	$ 73.3	$ 0.604	34.53%	0.34531
Distribution	111	40.6	$ 42.2	$ 1.040	19.88%	0.19880
EOR	24	8.8	$ 2.2	$ 0.248	1.02%	0.01024
Cogeneration	248	90.6	$ 30.9	$ 0.340	14.53%	0.14534
UEG	513	187.3	$ 63.7	$ 0.340	30.03%	0.30031
Noncore total	1,229	448.6	$ 212.3	$ 0.473	17.29%	0.17288
Grand Total	2,039	744.4	$ 1,227.9	$ 1.649	100.00%	1.00000

Source: PG&E, Gas Accord, Work Papers for the Gas Accord Settlement Agreement, Aug 20, 1996.
1997 is the base year used here (see FR97/ACCRD/ACCORD.WB2)
PG&E Advice Letter 1978-G, November 15, 1996 for EOR
EOR revenue from Page 14, line 1091
EOR unit charge is attachment I, page 8.
EOR demand based on unit charge and revenue.

Notes: Heat content = 1020 btu /cf

This was used to equate UEG and Cogen Distribution Costs

	Volume mmcfd	Volume bcf	Revenue mm$	Unit Price $/mcf
Cogeneration	248	90.6	$ 31.5	$ 0.348
UEG	513	187.3	$ 63.1	$ 0.337
Sum	761	277.9	$ 94.6	***$ 0.340***

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Table B-1

Pacific Gas & Electric Tracking Accounts
for Determining Other Regulatory Accounts

(Millions of 1998 Dollars)

TRACKING ACCOUNTS	**Residential**	**Small Commercial**	**Large Commercial**	**Distribution**	**Transmission**	**Cogen**	**UEG**
Cost/Credits to Base Revenues	$4.179	$0.940	$0.047	$0.526	$2.360	$0.806	$1.782
Balancing Accounts Total	$109.363	$34.214	$2.669	$6.946	$31.057	$15.636	$34.577
EOR Account	$1.331	$0.416	$0.011	$0.051	$0.070	$0.029	$0.065
ITCS Accounts	$9.353	$2.926	$0.231	$5.604	$25.244	$13.492	$29.833
Adjusted Balancing Accounts	$98.679	$30.872	$2.427	$1.291	$5.743	$2.115	$4.679
CARE	$5.784	$1.934	$0.153	$0.995	$4.483	$0.000	$0.000
Adjusted Tracking Accounts	$108.642	$33.746	$2.627	$2.812	$12.586	$2.921	$6.461
Demand (mdtherms)	$214.493	$67.422	$156.321	$34.704	$156.321	$83.544	$184.740
Unit Cost (1998 $/mmbtu)	$0.507	$0.501	$0.017	$0.081	$0.081	$0.035	$0.035
Unit Cost (1995 $/mcf)	$0.486	$0.480	$0.016	$0.078	$0.077	$0.034	$0.034

Source: PG&E, Biennial Cost Allocation Process, (Gas), Prepared Testimony, A. 97-03-002, pages 8-31, 8-33, 8-34, 8-35.

Notes: Deflator = 1.0631 and 1020 btu/cf.
EOR accounts are included in CEC Margin Allocation
ITCS is included separately in the sectorial end-use price summary.

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Table SCG -1

Southern California Gas Company

1997 Fuels Report

Staff Base Case

End-use Natural Gas Price Forecast by Sector

1995 $ per mcf

	Core			Noncore					System
Year	**Res**	**Comm**	**Indust**	**Comm**	**Indust**	**TEOR**	**Cogen**	**UEG**	**Average**
1989	6.62	6.11	6.11	4.96	4.63	3.07	4.08	4.08	4.99
1990	6.40	6.76	5.99	4.28	3.79	3.37	3.67	3.67	4.75
1991	6.99	7.34	7.34	3.91	3.64	2.86	3.22	3.22	4.72
1992	6.82	7.66	6.40	5.00	3.75	2.82	3.13	3.13	4.78
1993	7.24	7.65	6.71	4.98	3.73	3.16	3.14	3.14	5.01
1994	7.03	6.81	6.59	3.32	2.48	2.48	2.65	2.65	4.60
1995	6.69	6.55	5.85	2.39	2.29	2.01	2.26	2.26	4.26
1996	6.56	5.69	4.79	2.42	1.97	1.77	2.94	2.94	4.28
1997	6.44	4.82	3.72	2.44	2.44	2.20	2.30	2.30	3.97
1998	6.31	4.74	3.67	2.42	2.42	2.19	2.22	2.22	3.88
1999	6.28	4.71	3.64	2.40	2.39	2.19	2.15	2.15	3.82
2000	6.22	4.68	3.64	2.39	2.39	2.24	2.13	2.13	3.76
2001	6.07	4.56	3.53	2.32	2.32	2.29	2.06	2.06	3.65
2002	6.02	4.54	3.53	2.35	2.35	2.33	2.09	2.09	3.63
2003	5.98	4.52	3.54	2.38	2.38	2.36	2.12	2.12	3.65
2004	5.93	4.50	3.53	2.41	2.41	2.40	2.16	2.16	3.61
2005	5.90	4.50	3.55	2.44	2.44	2.42	2.19	2.19	3.64
2006	5.86	4.49	3.57	2.49	2.49	2.47	2.24	2.24	3.64
2007	5.89	4.53	3.61	2.54	2.54	2.52	2.30	2.30	3.68
2008	5.92	4.56	3.64	2.59	2.58	2.57	2.34	2.34	3.71
2009	5.95	4.59	3.68	2.63	2.63	2.61	2.39	2.39	3.75
2010	6.08	4.68	3.74	2.68	2.68	2.66	2.43	2.43	3.80
2011	6.09	4.71	3.77	2.75	2.74	2.73	2.49	2.49	3.83
2012	6.03	4.68	3.77	2.77	2.77	2.75	2.53	2.53	3.85
2013	6.05	4.70	3.80	2.83	2.82	2.81	2.58	2.58	3.87
2014	6.08	4.73	3.83	2.87	2.87	2.85	2.62	2.62	3.91
2015	6.09	4.76	3.86	2.93	2.92	2.91	2.68	2.68	3.95
2016	6.09	4.77	3.89	2.98	2.98	2.97	2.74	2.74	3.97
2017	6.09	4.79	3.91	3.04	3.04	3.02	2.80	2.80	4.00

Note: * 1989 - 1995 prices are historical for residential, commercial, industrial, and TEOR; prices between 1995 and 1997 are interpolated.
* 1989 - 1996 prices are historical for cogeneration and UEG,
* 1997 and later years are forecasted.

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Table SCG -2

Southern California Gas Company

1997 Fuels Report

Staff Base Case

Core End-Use Natural Gas Price Forecast by Sector

1995 $ per mcf

Residential Core Price

Year	SCG Fixed	Pipeline Demand	ITCS	Pitco/ Popco	Other Regulatory	Commodity	Total
1989							6.62
1990							6.40
1991							6.99
1992							6.82
1993							7.24
1994							7.03
1995							6.69
1996							6.56
1997	4.00	0.37	0.03	0.10	0.26	1.68	6.44
1998	3.88	0.36	0.03	0.10	0.26	1.69	6.31
1999	3.88	0.35	0.03	0.10	0.26	1.66	6.28
2000	3.80	0.34	0.03	0.10	0.26	1.69	6.22
2001	3.73	0.34	0.02	0.00	0.26	1.72	6.07
2002	3.66	0.33	0.01	0.00	0.26	1.76	6.02
2003	3.60	0.33	0.01	0.00	0.26	1.79	5.98
2004	3.52	0.32	0.00	0.00	0.26	1.82	5.93
2005	3.45	0.32	0.00	0.00	0.26	1.87	5.90
2006	3.38	0.32	0.00	0.00	0.26	1.91	5.86
2007	3.37	0.31	0.00	0.00	0.26	1.96	5.89
2008	3.35	0.31	0.00	0.00	0.26	2.00	5.92
2009	3.34	0.31	0.00	0.00	0.26	2.04	5.95
2010	3.43	0.30	0.00	0.00	0.26	2.08	6.08
2011	3.42	0.30	0.00	0.00	0.26	2.12	6.09
2012	3.32	0.30	0.00	0.00	0.26	2.15	6.03
2013	3.30	0.29	0.00	0.00	0.26	2.19	6.05
2014	3.30	0.29	0.00	0.00	0.26	2.23	6.08
2015	3.28	0.29	0.00	0.00	0.26	2.27	6.09
2016	3.25	0.29	0.00	0.00	0.26	2.30	6.09
2017	3.21	0.28	0.00	0.00	0.26	2.34	6.09

Commercial Core Price

Year	SCG Fixed	Pipeline Demand	ITCS	Pitco/ Popco	Other Regulatory	Commodity	Total
1989							6.11
1990							6.76
1991							7.34
1992							7.66
1993							7.65
1994							6.81
1995							6.55
1996							5.69
1997	2.44	0.37	0.03	0.10	0.21	1.68	4.82
1998	2.36	0.36	0.03	0.10	0.21	1.69	4.74
1999	2.36	0.35	0.03	0.10	0.21	1.66	4.71
2000	2.31	0.34	0.03	0.10	0.21	1.69	4.68
2001	2.27	0.34	0.02	0.00	0.21	1.72	4.56
2002	2.23	0.33	0.01	0.00	0.21	1.76	4.54
2003	2.19	0.33	0.01	0.00	0.21	1.79	4.52
2004	2.15	0.32	0.00	0.00	0.21	1.82	4.50
2005	2.10	0.32	0.00	0.00	0.21	1.87	4.50
2006	2.06	0.32	0.00	0.00	0.21	1.91	4.49
2007	2.05	0.31	0.00	0.00	0.21	1.96	4.53
2008	2.04	0.31	0.00	0.00	0.21	2.00	4.56
2009	2.04	0.31	0.00	0.00	0.21	2.04	4.59
2010	2.09	0.30	0.00	0.00	0.21	2.08	4.68
2011	2.08	0.30	0.00	0.00	0.21	2.12	4.71
2012	2.02	0.30	0.00	0.00	0.21	2.15	4.68
2013	2.01	0.29	0.00	0.00	0.21	2.19	4.70
2014	2.01	0.29	0.00	0.00	0.21	2.23	4.73
2015	2.00	0.29	0.00	0.00	0.21	2.27	4.76
2016	1.98	0.29	0.00	0.00	0.21	2.30	4.77
2017	1.96	0.28	0.00	0.00	0.21	2.34	4.79

Industrial Core Price

Year	SCG Fixed	Pipeline Demand	ITCS	Pitco/ Popco	Other Regulatory	Commodity	Total
1989							6.11
1990							5.99
1991							7.34
1992							6.40
1993							6.71
1994							6.59
1995							5.85
1996							4.79
1997	1.29	0.37	0.03	0.10	0.25	1.68	3.72
1998	1.25	0.36	0.03	0.10	0.25	1.69	3.67
1999	1.25	0.35	0.03	0.10	0.25	1.66	3.64
2000	1.22	0.34	0.03	0.10	0.25	1.69	3.64
2001	1.20	0.34	0.02	0.00	0.25	1.72	3.53
2002	1.18	0.33	0.01	0.00	0.25	1.76	3.53
2003	1.16	0.33	0.01	0.00	0.25	1.79	3.54
2004	1.13	0.32	0.00	0.00	0.25	1.82	3.53
2005	1.11	0.32	0.00	0.00	0.25	1.87	3.55
2006	1.09	0.32	0.00	0.00	0.25	1.91	3.57
2007	1.08	0.31	0.00	0.00	0.25	1.96	3.61
2008	1.08	0.31	0.00	0.00	0.25	2.00	3.64
2009	1.08	0.31	0.00	0.00	0.25	2.04	3.68
2010	1.10	0.30	0.00	0.00	0.25	2.08	3.74
2011	1.10	0.30	0.00	0.00	0.25	2.12	3.77
2012	1.07	0.30	0.00	0.00	0.25	2.15	3.77
2013	1.06	0.29	0.00	0.00	0.25	2.19	3.80
2014	1.06	0.29	0.00	0.00	0.25	2.23	3.83
2015	1.06	0.29	0.00	0.00	0.25	2.27	3.86
2016	1.04	0.29	0.00	0.00	0.25	2.30	3.89
2017	1.03	0.28	0.00	0.00	0.25	2.34	3.91

Note: 1989 - 1995 total prices are historical, obtained from QFER Form 6. Prices between 1994 and 1997 are interpolated
ITCS are interim transportation charges resultant from the implementation of FERC Order 636.

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Table SCG -3

Southern California Gas Company

1997 Fuels Report

Staff Base Case

NonCore End-Use Natural Gas Price Forecast by Sector

1995 $ per mcf

Commercial Noncore Price

Year	SCG Fixed	Pipeline Demand	ITCS	Pitco/ Popco	Other Regulatory	Commodity	Total
1989							4.96
1990							4.28
1991							3.91
1992							5.00
1993							4.98
1994							3.32
1995							2.39
1996							2.42
1997	0.41	0.09	0.13	0.06	0.10	1.66	2.44
1998	0.40	0.18	0.12	0.06	0.10	1.57	2.42
1999	0.41	0.21	0.09	0.06	0.10	1.53	2.40
2000	0.41	0.23	0.04	0.06	0.10	1.56	2.39
2001	0.40	0.26	0.02	0.06	0.00	1.58	2.32
2002	0.40	0.27	0.01	0.06	0.00	1.62	2.35
2003	0.39	0.28	0.01	0.06	0.00	1.65	2.38
2004	0.39	0.29	0.00	0.06	0.00	1.68	2.41
2005	0.38	0.28	0.00	0.06	0.00	1.72	2.44
2006	0.37	0.29	0.00	0.06	0.00	1.77	2.49
2007	0.37	0.30	0.00	0.06	0.00	1.81	2.54
2008	0.37	0.31	0.00	0.06	0.00	1.85	2.59
2009	0.37	0.31	0.00	0.06	0.00	1.90	2.63
2010	0.38	0.31	0.00	0.06	0.00	1.93	2.68
2011	0.38	0.34	0.00	0.06	0.00	1.97	2.75
2012	0.37	0.34	0.00	0.06	0.00	2.00	2.77
2013	0.37	0.36	0.00	0.06	0.00	2.04	2.83
2014	0.37	0.37	0.00	0.06	0.00	2.07	2.87
2015	0.37	0.39	0.00	0.06	0.00	2.11	2.93
2016	0.37	0.41	0.00	0.06	0.00	2.15	2.98
2017	0.37	0.43	0.00	0.06	0.00	2.19	3.04

Industrial Noncore Price

Year	SCG Fixed	Pipeline Demand	ITCS	Pitco/ Popco	Other Regulatory	Commodity	Total
1989							4.63
1990							3.79
1991							3.64
1992							3.75
1993							3.73
1994							2.48
1995							2.29
1996							1.97
1997	0.40	0.09	0.13	0.06	0.10	1.66	2.44
1998	0.40	0.18	0.12	0.06	0.10	1.57	2.42
1999	0.40	0.21	0.09	0.06	0.10	1.53	2.39
2000	0.40	0.23	0.04	0.06	0.10	1.56	2.39
2001	0.40	0.26	0.02	0.06	0.00	1.58	2.32
2002	0.39	0.27	0.01	0.06	0.00	1.62	2.35
2003	0.39	0.28	0.01	0.06	0.00	1.65	2.38
2004	0.38	0.29	0.00	0.06	0.00	1.68	2.41
2005	0.37	0.28	0.00	0.06	0.00	1.72	2.44
2006	0.37	0.29	0.00	0.06	0.00	1.77	2.49
2007	0.37	0.30	0.00	0.06	0.00	1.81	2.54
2008	0.37	0.31	0.00	0.06	0.00	1.85	2.58
2009	0.37	0.31	0.00	0.06	0.00	1.90	2.63
2010	0.38	0.31	0.00	0.06	0.00	1.93	2.68
2011	0.38	0.34	0.00	0.06	0.00	1.97	2.74
2012	0.37	0.34	0.00	0.06	0.00	2.00	2.77
2013	0.37	0.36	0.00	0.06	0.00	2.04	2.82
2014	0.37	0.37	0.00	0.06	0.00	2.07	2.87
2015	0.37	0.39	0.00	0.06	0.00	2.11	2.92
2016	0.37	0.41	0.00	0.06	0.00	2.15	2.98
2017	0.36	0.43	0.00	0.06	0.00	2.19	3.04

TEOR Noncore Price

Year	SCG Fixed	Pipeline Demand	ITCS	Pitco/ Popco	Other Regulatory	Commodity	Total
1989							3.07
1990							3.37
1991							2.86
1992							2.82
1993							3.16
1994							2.48
1995							2.01
1996							1.77
1997	0.45	0.09	0.00	0.00	0.00	1.66	2.20
1998	0.44	0.18	0.00	0.00	0.00	1.57	2.19
1999	0.45	0.21	0.00	0.00	0.00	1.53	2.19
2000	0.45	0.23	0.00	0.00	0.00	1.56	2.24
2001	0.44	0.26	0.00	0.00	0.00	1.58	2.29
2002	0.44	0.27	0.00	0.00	0.00	1.62	2.33
2003	0.43	0.28	0.00	0.00	0.00	1.65	2.36
2004	0.43	0.29	0.00	0.00	0.00	1.68	2.40
2005	0.41	0.28	0.00	0.00	0.00	1.72	2.42
2006	0.41	0.29	0.00	0.00	0.00	1.77	2.47
2007	0.41	0.30	0.00	0.00	0.00	1.81	2.52
2008	0.41	0.31	0.00	0.00	0.00	1.85	2.57
2009	0.41	0.31	0.00	0.00	0.00	1.90	2.61
2010	0.42	0.31	0.00	0.00	0.00	1.93	2.66
2011	0.42	0.34	0.00	0.00	0.00	1.97	2.73
2012	0.41	0.34	0.00	0.00	0.00	2.00	2.75
2013	0.41	0.36	0.00	0.00	0.00	2.04	2.81
2014	0.41	0.37	0.00	0.00	0.00	2.07	2.85
2015	0.41	0.39	0.00	0.00	0.00	2.11	2.91
2016	0.41	0.41	0.00	0.00	0.00	2.15	2.97
2017	0.41	0.43	0.00	0.00	0.00	2.19	3.02

Note: 1989 - 1995 total prices are historical, obtained from QFER Form 7. Prices between 1994 and 1997 are interpolated
ITCS are interim transportation charges resultant from the implementation of FERC Order 636.

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Table SCG -4

Southern California Gas Company

Staff Base Case

Noncore End-Use Natural Gas Price Forecast by Sector

1995 $ per mcf

	Cogen Noncore Price								UEG Noncore Price						
Year	**SCG Margin**	**Pipeline Demand**	**ITCS**	**Pitco/ Popco**	**Other Regulatory**	**Commodity**	**Total**	**Year**	**SCG Margin**	**Pipeline Demand**	**ITCS**	**Pitco/ Popco**	**Other Regulatory**	**Commodity**	**Total**
1989							4.08	**1989**							4.08
1990							3.67	**1990**							3.67
1991							3.22	**1991**							3.22
1992							3.13	**1992**							3.13
1993							3.14	**1993**							3.14
1994							2.65	**1994**							2.65
1995							2.26	**1995**							2.26
1996							2.94	**1996**							2.94
1997	0.17	0.36	0.13	0.10	0.07	1.47	2.30	**1997**	0.17	0.36	0.13	0.10	0.07	1.47	2.30
1998	0.17	0.20	0.12	0.10	0.06	1.57	2.22	**1998**	0.17	0.20	0.12	0.10	0.06	1.57	2.22
1999	0.17	0.21	0.09	0.10	0.05	1.53	2.15	**1999**	0.17	0.21	0.09	0.10	0.05	1.53	2.15
2000	0.17	0.23	0.04	0.10	0.03	1.56	2.13	**2000**	0.17	0.23	0.04	0.10	0.03	1.56	2.13
2001	0.17	0.26	0.02	0.00	0.03	1.58	2.06	**2001**	0.17	0.26	0.02	0.00	0.03	1.58	2.06
2002	0.16	0.27	0.01	0.00	0.03	1.62	2.09	**2002**	0.16	0.27	0.01	0.00	0.03	1.62	2.09
2003	0.16	0.28	0.01	0.00	0.03	1.65	2.12	**2003**	0.16	0.28	0.01	0.00	0.03	1.65	2.12
2004	0.16	0.29	0.00	0.00	0.03	1.68	2.16	**2004**	0.16	0.29	0.00	0.00	0.03	1.68	2.16
2005	0.16	0.28	0.00	0.00	0.03	1.72	2.19	**2005**	0.16	0.28	0.00	0.00	0.03	1.72	2.19
2006	0.15	0.29	0.00	0.00	0.03	1.77	2.24	**2006**	0.15	0.29	0.00	0.00	0.03	1.77	2.24
2007	0.15	0.30	0.00	0.00	0.03	1.81	2.30	**2007**	0.15	0.30	0.00	0.00	0.03	1.81	2.30
2008	0.15	0.31	0.00	0.00	0.03	1.85	2.34	**2008**	0.15	0.31	0.00	0.00	0.03	1.85	2.34
2009	0.15	0.31	0.00	0.00	0.03	1.90	2.39	**2009**	0.15	0.31	0.00	0.00	0.03	1.90	2.39
2010	0.16	0.31	0.00	0.00	0.03	1.93	2.43	**2010**	0.16	0.31	0.00	0.00	0.03	1.93	2.43
2011	0.16	0.34	0.00	0.00	0.03	1.97	2.49	**2011**	0.16	0.34	0.00	0.00	0.03	1.97	2.49
2012	0.15	0.34	0.00	0.00	0.03	2.00	2.53	**2012**	0.15	0.34	0.00	0.00	0.03	2.00	2.53
2013	0.15	0.36	0.00	0.00	0.03	2.04	2.58	**2013**	0.15	0.36	0.00	0.00	0.03	2.04	2.58
2014	0.15	0.37	0.00	0.00	0.03	2.07	2.62	**2014**	0.15	0.37	0.00	0.00	0.03	2.07	2.62
2015	0.15	0.39	0.00	0.00	0.03	2.11	2.68	**2015**	0.15	0.39	0.00	0.00	0.03	2.11	2.68
2016	0.15	0.41	0.00	0.00	0.03	2.15	2.74	**2016**	0.15	0.41	0.00	0.00	0.03	2.15	2.74
2017	0.15	0.43	0.00	0.00	0.03	2.19	2.80	**2017**	0.15	0.43	0.00	0.00	0.03	2.19	2.80

Note: 1989 - 1996 total prices are historical, obtained from UMFOR
ITCS are interim transportation charges resultant from the implementation of FERC Order 636.

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Table SCG -5

Southern California Gas Service Area
ER98/FR97
Staff Base Case
Electricity Generation Gas Price Forecast

1995 $ per mmBtu

	Utility Electric Generation				
Year	**Fixed Price**	**Variable Price**	**Commodity Price**	**Dispatch Price**	**Total Price**
1989				3.11	3.92
1990				2.99	3.51
1991				2.58	3.11
1992				2.49	3.00
1993				2.51	3.02
1994				2.05	2.55
1995				2.20	2.20
1996				2.85	2.85
1997	0.51	0.29	1.41	2.21	2.21
1998	0.36	0.27	1.51	2.14	2.14
1999	0.36	0.23	1.48	2.07	2.07
2000	0.39	0.16	1.50	2.05	2.05
2001	0.41	0.05	1.52	1.98	1.98
2002	0.41	0.04	1.56	2.01	2.01
2003	0.43	0.03	1.58	2.04	2.04
2004	0.44	0.03	1.61	2.08	2.08
2005	0.42	0.03	1.66	2.11	2.11
2006	0.43	0.03	1.70	2.16	2.16
2007	0.44	0.03	1.74	2.21	2.21
2008	0.44	0.03	1.78	2.25	2.25
2009	0.45	0.03	1.82	2.30	2.30
2010	0.45	0.03	1.86	2.34	2.34
2011	0.48	0.03	1.89	2.40	2.40
2012	0.48	0.03	1.92	2.43	2.43
2013	0.50	0.03	1.96	2.48	2.48
2014	0.50	0.03	1.99	2.52	2.52
2015	0.52	0.03	2.03	2.58	2.58
2016	0.54	0.03	2.07	2.63	2.63
2017	0.56	0.03	2.10	2.69	2.69

Notes:
* 1989 - 1996 total price are historical taken from SCE's UMFOR.
* 1989 - 1996 dispatch prices are estimates.
* All cost are assumed to be variable costs.
* IntrastateTransport includes all utility fixed and variable charges, ITCS, and PITCO/POPCO charges, based on Decision 97-04-082.
* ITCS based on CPUC BCAP Decison 97-04-082, and NARG run analysis.
* PITCO/POPCO is based on the Global Settlement.
* Commodity price = California Border price less interstate pipeline demand charges.
* Assumed 1040 btu per cf for forecasted prices.
* Inflation based on 1995=100 using Apr. 16, 1997 deflators.
* Resource plan based on ER96.
* May not sum due to rounding.

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Table A-2
Southern California Gas Marginal Cost Distribution
Average Year Requirement
1996 BCAP Decison 97-04-082

April 23, 1997

Sector	Throughput mmdth	Rate $/dth	Revenue $mm	Volume mmcfd	Allocation Factors	
Core						
Residentrial	266.706	$ 4.278	$ 1,140.921	715	83.3%	0.832564
G-10	83.903	$ 2.606	$ 218.671	225	16.0%	0.159571
G-20	5.141	$ 0.955	$ 4.908	14	0.4%	0.007866
Gas Engine	2.454	$ 2.392	$ 5.871	7		
Subtotal	358.204	$ 3.826	$ 1,370.371	960	90.4%	0.903752
Noncore						
Commercial	19.933	$ 0.480	$ 9.558	53	6.5%	0.065491
Industrial	102.460	$ 0.480	$ 49.131	275	33.7%	0.336648
G-30	122.393	$ 0.480	$ 58.689	328	40.2%	0.402139
EOR	58.228	$ 0.532	$ 30.992	156	21.2%	0.212358
Cogen	82.483	$ 0.200	$ 16.490	221	11.3%	0.112988
UEG	198.939	$ 0.200	$ 39.771	533	27.3%	0.272514
Subtotal	462.043	$ 0.316	$ 145.942	1,239	9.6%	0.096248
Total	820.247	$ 1.849	$ 1,516.313	2,199	100.0%	1.000000

Source: CPUC Decision 97-04-082

Core: Allocated Margin, Appendix D, Page 5, line 38 (includes storage for core).
Average throughput, Appendix D. Page 5, line 39
Gas Engines included with G-20 allocation factors

Noncore: Allocated Margin, Appendix D, Page 10, line 38
Average Throughput, Appendix D, Page 5, Line 39.

Note: Pipeline demand charges, balancing accounts, and ITCS are not included in margin requirements
G-30 split into comm and indust using CGR 95 demand of 57 and 293 mmcfd respectfully.

Cogen and UEG margin averaging

	Throughput mmdth	Rate $/dth	Revenue $mm
Cogen	82.483	0.2110	17.407
UEG	198.939	0.1953	38.854
	281.422	*0.1999*	56.261

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Table B-2

Southern California Gas Tracking Accounts
for Determining Other Regulatory Accounts

(Millions of 1997 Dollars)

ACCOUNTS	**Residential**	**G-10**	**G-20**	**G-30**	**Cogen**	**UEG**	**EOR**
Other Operating Costs and Revenues							
Total	13.152	-0.502	-0.133	0.598	1.145	2.046	1.624
Unaccounted for Gas	15.842	0.675	-0.065	0.737	1.231	2.256	1.540
Ad justed Other Costs	-2.690	-1.177	-0.068	-0.139	-0.086	-0.210	0.084
Tracking Accounts							
Total	81.238	20.245	1.429	7.445	2.474	5.984	0.000
EOR Account	8.436	1.501	0.035	0.408	0.123	0.281	0.000
Adjusted Tracking	72.802	18.744	1.394	7.037	2.351	5.703	0.000
Sum	70.112	17.567	1.326	6.898	2.265	5.493	0.084
Demand (mdtherms)	266.706	83.903	5.141	122.393	82.483	198.939	58.228
Unit Cost (1997 $/mmbtu)	$0.263	$0.209	$0.258	$0.056	$0.027	$0.028	$0.001
Unit cost (1995 $/mcf)	$0.259	$0.207	$0.254	$0.056	$0.027	$0.027	$0.001

Source: SCG BCAP Decision 97-04-082, Appendix D, pages 6, 7, 11, 12.

Note: Deflator = 1.0391 and 1025 btu/cf.
Unaccounted for gas is included in NARG shrinkage.
EOR is included in margin allocation

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Table SDG&E -1

San Diego Gas & Electric Company

1997 Fuels Report

Staff Base Case

End-use Natural Gas Price Forecast by Sector

1995 $ per mcf

	Core			Noncore					System
Year	**Res**	**Comm**	**Indust**	**Comm**	**Indust**	**TEOR**	**Cogen**	**UEG**	**Average**
1989	6.74	6.68	6.68	4.57	4.57	0.00	4.05	4.05	5.17
1990	6.43	6.61	6.40	4.41	4.41	0.00	3.71	3.71	5.06
1991	6.05	6.13	6.13	3.88	3.88	0.00	3.25	3.25	4.61
1992	6.45	6.67	6.67	4.02	4.02	0.00	3.20	3.20	4.71
1993	6.85	6.87	6.44	2.57	2.49	0.00	3.33	3.33	4.89
1994	6.89	6.71	5.53	3.60	3.90	0.00	3.04	3.04	4.88
1995	6.44	6.32	5.31	2.71	2.74	0.00	2.18	2.18	4.01
1996	6.71	5.14	4.32	2.73	2.74	0.00	2.53	2.53	4.25
1997	6.98	3.96	3.33	2.74	2.74	0.00	2.52	2.52	4.03
1998	6.96	3.99	3.37	2.78	2.78	0.00	2.63	2.63	4.04
1999	6.86	3.96	3.36	2.74	2.74	0.00	2.52	2.52	4.03
2000	6.87	4.01	3.41	2.74	2.74	0.00	2.60	2.60	4.04
2001	6.79	4.01	3.43	2.79	2.79	0.00	2.70	2.70	3.96
2002	6.66	3.98	3.42	2.82	2.82	0.00	2.73	2.73	3.82
2003	6.72	4.03	3.47	2.86	2.86	0.00	2.66	2.66	3.85
2004	6.66	4.04	3.49	2.89	2.89	0.00	2.75	2.75	3.85
2005	6.65	4.05	3.51	2.91	2.91	0.00	2.73	2.73	3.87
2006	6.55	4.04	3.52	2.95	2.95	0.00	2.82	2.82	3.85
2007	6.51	4.06	3.56	3.00	3.00	0.00	2.87	2.87	3.84
2008	6.47	4.08	3.58	3.04	3.04	0.00	2.90	2.90	3.84
2009	6.48	4.11	3.62	3.08	3.08	0.00	2.91	2.91	3.89
2010	6.45	4.12	3.64	3.10	3.10	0.00	2.96	2.96	3.91
2011	6.44	4.17	3.70	3.18	3.18	0.00	3.06	3.06	3.95
2012	6.42	4.18	3.72	3.21	3.21	0.00	3.08	3.08	3.96
2013	6.41	4.22	3.77	3.27	3.27	0.00	3.15	3.15	3.99
2014	6.39	4.24	3.80	3.31	3.31	0.00	3.18	3.18	4.00
2015	6.42	4.29	3.86	3.38	3.38	0.00	3.24	3.24	4.06
2016	6.45	4.35	3.92	3.44	3.44	0.00	3.32	3.32	4.12
2017	6.48	4.41	3.98	3.52	3.52	0.00	3.40	3.40	4.18

Note: * 1989 - 1995 prices are historical for residential, commercial, industrial, and TEOR obtained from QFER Form 7.
* 1989 - 1996 prices are historical prices for cogeneration and UEG
* 1997 and later prices are forecasted.

July 25, 1997

Table SDG&E -2

San Diego Gas & Electric Company

1997 Fuels Report

Staff Base Case

Core End-Use Natural Gas Price Forecast by Sector

1995 $ per mcf

	Residential Core Price							Commercial Core Price								Industrial Core Price							
Year	SDG&E Fixed	Pipeline Demand	ITCS	Pitco/ Popco	Other Regulatory	Commodity	Total	Year	SDG&E Fixed	Pipeline Demand	ITCS	Pitco/ Popco	Other Regulatory	Commodity	Total	Year	SDG&E Fixed	Pipeline Demand	ITCS	Pitco/ Popco	Other Regulatory	Commodity	Total
1989							6.74	**1989**							6.68	**1989**							6.68
1990							6.43	**1990**							6.61	**1990**							6.40
1991							6.05	**1991**							6.13	**1991**							6.13
1992							6.45	**1992**							6.67	**1992**							6.67
1993							6.85	**1993**							6.87	**1993**							6.44
1994							6.89	**1994**							6.71	**1994**							5.53
1995							6.44	**1995**							6.32	**1995**							5.31
1996							6.71	**1996**							5.14	**1996**							4.32
1997	4.84	0.20	0.03	0.00	0.27	1.64	6.98	**1997**	1.97	0.20	0.03	0.00	0.12	1.64	3.96	**1997**	1.34	0.20	0.03	0.00	0.12	1.64	3.33
1998	4.75	0.27	0.03	0.00	0.27	1.64	6.96	**1998**	1.93	0.27	0.03	0.00	0.12	1.64	3.99	**1998**	1.31	0.27	0.03	0.00	0.12	1.64	3.37
1999	4.64	0.29	0.03	0.00	0.27	1.64	6.86	**1999**	1.89	0.29	0.03	0.00	0.12	1.64	3.96	**1999**	1.28	0.29	0.03	0.00	0.12	1.64	3.36
2000	4.57	0.30	0.03	0.00	0.27	1.69	6.87	**2000**	1.86	0.30	0.03	0.00	0.12	1.69	4.01	**2000**	1.26	0.30	0.03	0.00	0.12	1.69	3.41
2001	4.43	0.32	0.02	0.00	0.27	1.74	6.79	**2001**	1.80	0.32	0.02	0.00	0.12	1.74	4.01	**2001**	1.23	0.32	0.02	0.00	0.12	1.74	3.43
2002	4.27	0.32	0.01	0.00	0.27	1.79	6.66	**2002**	1.74	0.32	0.01	0.00	0.12	1.79	3.98	**2002**	1.18	0.32	0.01	0.00	0.12	1.79	3.42
2003	4.27	0.33	0.01	0.00	0.27	1.84	6.72	**2003**	1.74	0.33	0.01	0.00	0.12	1.84	4.03	**2003**	1.18	0.33	0.01	0.00	0.12	1.84	3.47
2004	4.17	0.34	0.00	0.00	0.27	1.88	6.66	**2004**	1.70	0.34	0.00	0.00	0.12	1.88	4.04	**2004**	1.15	0.34	0.00	0.00	0.12	1.88	3.49
2005	4.13	0.33	0.00	0.00	0.27	1.92	6.65	**2005**	1.68	0.33	0.00	0.00	0.12	1.92	4.05	**2005**	1.14	0.33	0.00	0.00	0.12	1.92	3.51
2006	3.97	0.33	0.00	0.00	0.27	1.97	6.55	**2006**	1.62	0.33	0.00	0.00	0.12	1.97	4.04	**2006**	1.10	0.33	0.00	0.00	0.12	1.97	3.52
2007	3.87	0.35	0.00	0.00	0.27	2.02	6.51	**2007**	1.57	0.35	0.00	0.00	0.12	2.02	4.06	**2007**	1.07	0.35	0.00	0.00	0.12	2.02	3.56
2008	3.77	0.35	0.00	0.00	0.27	2.07	6.47	**2008**	1.54	0.35	0.00	0.00	0.12	2.07	4.08	**2008**	1.04	0.35	0.00	0.00	0.12	2.07	3.58
2009	3.74	0.35	0.00	0.00	0.27	2.11	6.48	**2009**	1.52	0.35	0.00	0.00	0.12	2.11	4.11	**2009**	1.03	0.35	0.00	0.00	0.12	2.11	3.62
2010	3.67	0.35	0.00	0.00	0.27	2.15	6.45	**2010**	1.49	0.35	0.00	0.00	0.12	2.15	4.12	**2010**	1.01	0.35	0.00	0.00	0.12	2.15	3.64
2011	3.57	0.38	0.00	0.00	0.27	2.21	6.44	**2011**	1.45	0.38	0.00	0.00	0.12	2.21	4.17	**2011**	0.99	0.38	0.00	0.00	0.12	2.21	3.70
2012	3.51	0.38	0.00	0.00	0.27	2.25	6.42	**2012**	1.43	0.38	0.00	0.00	0.12	2.25	4.18	**2012**	0.97	0.38	0.00	0.00	0.12	2.25	3.72
2013	3.44	0.39	0.00	0.00	0.27	2.30	6.41	**2013**	1.40	0.39	0.00	0.00	0.12	2.30	4.22	**2013**	0.95	0.39	0.00	0.00	0.12	2.30	3.77
2014	3.38	0.40	0.00	0.00	0.27	2.35	6.39	**2014**	1.37	0.40	0.00	0.00	0.12	2.35	4.24	**2014**	0.93	0.40	0.00	0.00	0.12	2.35	3.80
2015	3.33	0.42	0.00	0.00	0.27	2.40	6.42	**2015**	1.35	0.42	0.00	0.00	0.12	2.40	4.29	**2015**	0.92	0.42	0.00	0.00	0.12	2.40	3.86
2016	3.28	0.43	0.00	0.00	0.27	2.46	6.45	**2016**	1.34	0.43	0.00	0.00	0.12	2.46	4.35	**2016**	0.91	0.43	0.00	0.00	0.12	2.46	3.92
2017	3.24	0.45	0.00	0.00	0.27	2.52	6.48	**2017**	1.32	0.45	0.00	0.00	0.12	2.52	4.41	**2017**	0.89	0.45	0.00	0.00	0.12	2.52	3.98

Note: 1989 - 1995 total prices are historical, obtained from QFER Form 7. 1996 is interpolated.
ITCS are interim transportation charges resultant from the implementation of FERC Order 636.

July 25, 1997

Table SDG&E -3

San Diego Gas & Electric Company

1997 Fuels Report

Staff Base Case

Noncore End-Use Natural Gas Price Forecast by Sector

1995 $ per mcf

	Commercial Noncore Price						
Year	**SGD&E Fixed**	**Pipeline Demand**	**ITCS**	**Pitco/ Popco**	**Other Regulatory**	**Commodity**	**Total**
1989							4.57
1990							4.41
1991							3.88
1992							4.02
1993							2.57
1994							3.60
1995							2.71
1996							2.73
1997	0.74	0.19	0.14	0.00	0.03	1.64	2.74
1998	0.71	0.26	0.13	0.00	0.03	1.64	2.78
1999	0.68	0.29	0.10	0.00	0.03	1.64	2.74
2000	0.67	0.30	0.04	0.00	0.03	1.70	2.74
2001	0.66	0.32	0.02	0.00	0.03	1.75	2.79
2002	0.65	0.32	0.01	0.00	0.03	1.80	2.82
2003	0.64	0.33	0.01	0.00	0.03	1.85	2.86
2004	0.63	0.34	0.00	0.00	0.03	1.89	2.89
2005	0.62	0.33	0.00	0.00	0.03	1.93	2.91
2006	0.60	0.33	0.00	0.00	0.03	1.99	2.95
2007	0.58	0.35	0.00	0.00	0.03	2.04	3.00
2008	0.57	0.35	0.00	0.00	0.03	2.08	3.04
2009	0.56	0.35	0.00	0.00	0.03	2.13	3.08
2010	0.55	0.36	0.00	0.00	0.03	2.16	3.10
2011	0.54	0.38	0.00	0.00	0.03	2.23	3.18
2012	0.53	0.38	0.00	0.00	0.03	2.27	3.21
2013	0.52	0.40	0.00	0.00	0.03	2.32	3.27
2014	0.51	0.40	0.00	0.00	0.03	2.36	3.31
2015	0.50	0.42	0.00	0.00	0.03	2.42	3.38
2015	0.50	0.44	0.00	0.00	0.03	2.47	3.44
2015	0.49	0.46	0.00	0.00	0.03	2.53	3.52

	Industrial Noncore Price						
Year	**SCG Fixed**	**Pipeline Demand**	**ITCS**	**Pitco/ Popco**	**Other Regulatory**	**Commodity**	**Total**
1989							4.57
1990							4.41
1991							3.88
1992							4.02
1993							2.49
1994							3.90
1995							2.74
1996							2.74
1997	0.74	0.19	0.14	0.00	0.03	1.64	2.74
1998	0.71	0.26	0.13	0.00	0.03	1.64	2.78
1999	0.68	0.29	0.10	0.00	0.03	1.64	2.74
2000	0.67	0.30	0.04	0.00	0.03	1.70	2.74
2001	0.66	0.32	0.02	0.00	0.03	1.75	2.79
2002	0.65	0.32	0.01	0.00	0.03	1.80	2.82
2003	0.64	0.33	0.01	0.00	0.03	1.85	2.86
2004	0.63	0.34	0.00	0.00	0.03	1.89	2.89
2005	0.62	0.33	0.00	0.00	0.03	1.93	2.91
2006	0.60	0.33	0.00	0.00	0.03	1.99	2.95
2007	0.58	0.35	0.00	0.00	0.03	2.04	3.00
2008	0.57	0.35	0.00	0.00	0.03	2.08	3.04
2009	0.56	0.35	0.00	0.00	0.03	2.13	3.08
2010	0.55	0.36	0.00	0.00	0.03	2.16	3.10
2011	0.54	0.38	0.00	0.00	0.03	2.23	3.18
2012	0.53	0.38	0.00	0.00	0.03	2.27	3.21
2013	0.52	0.40	0.00	0.00	0.03	2.32	3.27
2014	0.51	0.40	0.00	0.00	0.03	2.36	3.31
2015	0.50	0.42	0.00	0.00	0.03	2.42	3.38
2016	0.50	0.44	0.00	0.00	0.03	2.47	3.44
2017	0.49	0.46	0.00	0.00	0.03	2.53	3.52

Note: 1989 - 1995 total prices are historical, obtained from QFER Form 7; 1996 is interpolated

ITCS are interim transportation charges resultant from the implementation of FERC Order 636.

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Table SDG&E -4

San Diego Gas & Electric Company

1997 Fuels Report

Staff Base Case

Core End-Use Natural Gas Price Forecast by Sector

1995 $ per mcf

	Cogen Noncore Price						
Year	**Total Margin**	**Pipeline Demand**	**ITCS**	**Pitco/ Popco**	**Other Regulatory**	**Commodity**	**Total**
1989							4.05
1990							3.71
1991							3.25
1992							3.20
1993							3.33
1994							3.04
1995							2.18
1996							2.53
1997	0.45	0.19	0.14	0.00	0.10	1.64	2.52
1998	0.49	0.26	0.13	0.00	0.10	1.64	2.63
1999	0.39	0.29	0.10	0.00	0.10	1.64	2.52
2000	0.45	0.30	0.04	0.00	0.10	1.70	2.60
2001	0.50	0.32	0.02	0.00	0.10	1.75	2.70
2002	0.50	0.32	0.01	0.00	0.10	1.80	2.73
2003	0.37	0.33	0.01	0.00	0.10	1.85	2.66
2004	0.42	0.34	0.00	0.00	0.10	1.89	2.75
2005	0.36	0.33	0.00	0.00	0.10	1.93	2.73
2006	0.40	0.33	0.00	0.00	0.10	1.99	2.82
2007	0.38	0.35	0.00	0.00	0.10	2.04	2.87
2008	0.36	0.35	0.00	0.00	0.10	2.08	2.90
2009	0.32	0.35	0.00	0.00	0.10	2.13	2.91
2010	0.34	0.36	0.00	0.00	0.10	2.16	2.96
2011	0.35	0.38	0.00	0.00	0.10	2.23	3.06
2012	0.33	0.38	0.00	0.00	0.10	2.27	3.08
2013	0.33	0.40	0.00	0.00	0.10	2.32	3.15
2014	0.32	0.40	0.00	0.00	0.10	2.36	3.18
2015	0.30	0.42	0.00	0.00	0.10	2.42	3.24
2016	0.31	0.44	0.00	0.00	0.10	2.47	3.32
2017	0.30	0.46	0.00	0.00	0.10	2.53	3.40

	UEG Noncore Price							
	SDG&E Margin		**Pipeline**		**Pitco/**	**Other**		
Year	**Fixed**	**Variable**	**Demand**	**ITCS**	**Popco**	**Regulatory**	**Commodity**	**Total**
1989								4.05
1990								3.71
1991								3.25
1992								3.20
1993								3.33
1994								3.04
1995								2.18
1996								2.53
1997	0.26	0.19	0.19	0.14	0.00	0.10	1.64	2.52
1998	0.30	0.19	0.26	0.13	0.00	0.10	1.64	2.63
1999	0.20	0.19	0.29	0.10	0.00	0.10	1.64	2.52
2000	0.27	0.19	0.30	0.04	0.00	0.10	1.70	2.60
2001	0.31	0.19	0.32	0.02	0.00	0.10	1.75	2.70
2002	0.31	0.19	0.32	0.01	0.00	0.10	1.80	2.73
2003	0.18	0.19	0.33	0.01	0.00	0.10	1.85	2.66
2004	0.23	0.19	0.34	0.00	0.00	0.10	1.89	2.75
2005	0.18	0.19	0.33	0.00	0.00	0.10	1.93	2.73
2006	0.21	0.19	0.33	0.00	0.00	0.10	1.99	2.82
2007	0.19	0.19	0.35	0.00	0.00	0.10	2.04	2.87
2008	0.18	0.19	0.35	0.00	0.00	0.10	2.08	2.90
2009	0.14	0.19	0.35	0.00	0.00	0.10	2.13	2.91
2010	0.15	0.19	0.36	0.00	0.00	0.10	2.16	2.96
2011	0.16	0.19	0.38	0.00	0.00	0.10	2.23	3.06
2012	0.14	0.19	0.38	0.00	0.00	0.10	2.27	3.08
2013	0.14	0.19	0.40	0.00	0.00	0.10	2.32	3.15
2014	0.13	0.19	0.40	0.00	0.00	0.10	2.36	3.18
2015	0.11	0.19	0.42	0.00	0.00	0.10	2.42	3.24
2016	0.12	0.19	0.44	0.00	0.00	0.10	2.47	3.32
2017	0.12	0.19	0.46	0.00	0.00	0.10	2.53	3.40

Note: 1989 - 1996 total prices are historical, obtained form UMFOR.

ITCS are interim transportation charges resultant from the implementation of FERC Order 636.

Table SDG&E -5
San Diego Gas & Electric Service Area
ER98/FR97
Staff Base Case
Electricity Generation Gas Price Forecast

1995 $ per mmBtu

	Utility Electric Generation				
Year	**Fixed Price**	**Variable Price**	**Commodity Price**	**Dispatch Price**	**Total Price**
1989				0.00	3.73
1990				2.01	3.42
1991				2.03	3.00
1992				2.10	2.95
1993				2.12	3.09
1994				2.09	2.85
1995				2.07	2.72
1996				2.04	2.59
1997	0.44	0.32	1.60	1.92	2.36
1998	0.55	0.31	1.60	1.91	2.46
1999	0.48	0.28	1.60	1.88	2.35
2000	0.55	0.22	1.66	1.88	2.43
2001	0.62	0.20	1.71	1.91	2.53
2002	0.62	0.19	1.76	1.95	2.57
2003	0.50	0.19	1.80	1.99	2.49
2004	0.56	0.18	1.85	2.03	2.59
2005	0.49	0.18	1.88	2.07	2.56
2006	0.53	0.18	1.94	2.12	2.65
2007	0.53	0.18	1.99	2.17	2.70
2008	0.51	0.18	2.03	2.21	2.73
2009	0.48	0.18	2.07	2.26	2.74
2010	0.50	0.18	2.11	2.29	2.79
2011	0.53	0.18	2.17	2.36	2.89
2012	0.51	0.18	2.21	2.39	2.90
2013	0.53	0.18	2.26	2.44	2.97
2014	0.52	0.18	2.30	2.49	3.00
2015	0.52	0.18	2.36	2.54	3.06
2016	0.55	0.18	2.41	2.60	3.14
2017	0.56	0.18	2.47	2.65	3.21

Notes:
* 1989 - 1996 total price are historic from SDG&E's UMFOR.
* 1989 - 1996 dispatch prices are estimates.
* Forecasted fixed and variable costs are based on CPUC Decision No. 97-04-082.
* Fixed includes utility and interstate pipeline fixed costs.
* Variable includes the second tier volumetric charge, ITCS, Other Regulatory, and PITCO/POPCO charges.
* ITCS based on CPUC BCAP Decison 97-04-082, and NARG run analysis.
* PITCO/POPCO is based on the Global Settlement.
* Commodity price = California Border price less interstate pipeline demand charges.
* Assumed 1025 btu per cf for forecasted prices.
* Inflation based on 1995=100 using Apr. 16, 1997 deflators.
* Resource plan based on ER96.
* May not sum due to rounding.

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Table A-3
San Diego Gas & Electric Marginal Cost Distribution
Average Year Requirement
1996 BCAP Decison 97-04-082

April 23, 1997

Sector	Throughput mmdth	Rate $/dth	Revenue Requirements Margin $mm	SoCal Trans $mm	Storage $mm	Total Revenue $mm	Volume mmcfd	Allocation Factors	
Core									
Residential	34.073	$ 4.977	$ 154.397	$ 10.164	$ 5.030	$ 169.591	91	86.8%	0.86789
Sm Commercial	11.906	$ 2.038	$ 19.844	$ 3.392	$ 1.034	$ 24.270	32	12.4%	0.12420
Lrg Commercial	1.061	$ 1.456	$ 1.104	$ 0.355	$ 0.086	$ 1.545	3	0.8%	0.00791
Subtotal	47.040	$ 4.154	$ 175.345	$ 13.911	$ 6.150	$ 195.406	126	83.7%	0.83712
Noncore									
Com/Industrial	10.223	$ 0.842	$ 5.627	$ 2.864	$ 0.120	$ 8.611	27	22.6%	0.22649
Cogeneration	13.507	$ 0.656	$ 4.906	$ 3.784	$ 0.164	$ 8.854	36	23.3%	0.23288
UEG	42.130	$ 0.488	$ 8.307	$ 11.807	$ 0.441	$ 20.555	113	54.1%	0.54064
Subtotal	65.859	$ 0.577	$ 18.840	$ 18.455	$ 0.725	$ 38.020	177	16.3%	0.16288
Total	112.899	$ 2.068	$ 194.185	$ 32.366	$ 6.875	$ 233.426	303	100.0%	1.00000

Source: CPUC Decision 97-04-082 issued April 23, 1997
Allocated Margin, Appendix E, Page 1, line 5.
Socal Gas Transportaition, Appendix E, Page 1, line 14.
Socal Gas Storage, Appendix E, Page 1, line 15.
Average throughput, Appendix C, Page 1, Col A, and Appendix E, Page 2, line 27.

Note: NGV included with small commercial
CGR indicates all noncore com/ind is industrial.

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Table B-3

San Diego Gas & Electric Tracking Accounts
for Determining Other Regulatory Accounts

(Millions of 1997 Dollars)

ACCOUNTS	**Residential**	**Small Commercial**	**Large Commercial**	**Commercial Inmdustrial**	**Cogen**	**UEG**
Balance Accounts	5.068	1.770	0.189	0.798	0.944	3.668
CARE Accounts	1.015	-0.918	-0.082	-0.788	0.000	0.000
Other Costs	1.126	0.330	0.033	0.250	0.331	0.678
Msc Revenues	2.230	0.286	0.015	0.081	0.071	0.120
Total	9.439	1.468	0.155	0.341	1.346	4.466
Demand (mdbtu)	34.073	11.906	1.270	10.223	13.507	41.921
Unit Cost (1997$/mmbtu)	$0.277	$0.123	$0.122	$0.033	$0.105	$0.105
Unit Cost (1995 $/mcf)	$0.273	$0.122	$0.120	$0.033	$0.103	$0.103

Source: SCG BCAP Decision 97-04-082, Appendix E, pages 1 and 2.

Note: Deflator = 1.0391 and 1025 btu/cf.

Table A-4

Forecasted Annual Revenue Requirements
for California Utilities

(Millions of 1995 Dollars)

	PG&E		SCG	SDG&E
Year	BackBone	Adj Margin	Margin	Margin
1997	$ 193.9	$ 1,210.4	$ 1,426.4	$ 232.3
1998	$ 193.2	$ 1,206.0	$ 1,396.9	$ 232.4
1999	$ 191.6	$ 1,196.2	$ 1,415.4	$ 226.8
2000	$ 190.2	$ 1,187.2	$ 1,404.0	$ 228.1
2001	$ 188.7	$ 1,178.3	$ 1,398.9	$ 229.0
2002	$ 187.3	$ 1,169.5	$ 1,391.5	$ 230.2
2003	$ 196.3	$ 1,225.3	$ 1,382.7	$ 230.3
2004	$ 194.6	$ 1,215.0	$ 1,373.8	$ 230.0
2005	$ 184.0	$ 1,148.8	$ 1,358.6	$ 228.9
2006	$ 183.0	$ 1,142.5	$ 1,346.5	$ 225.5
2007	$ 182.2	$ 1,137.6	$ 1,356.4	$ 224.1
2008	$ 179.6	$ 1,121.3	$ 1,366.8	$ 222.4
2009	$ 180.6	$ 1,127.1	$ 1,378.4	$ 220.7
2010	$ 179.4	$ 1,119.8	$ 1,389.2	$ 218.8
2011	$ 178.5	$ 1,114.2	$ 1,400.7	$ 217.8
2012	$ 177.6	$ 1,108.6	$ 1,412.2	$ 216.7
2013	$ 176.7	$ 1,103.2	$ 1,423.4	$ 215.8
2014	$ 176.1	$ 1,099.6	$ 1,434.7	$ 214.9
2015	$ 175.3	$ 1,094.1	$ 1,445.9	$ 214.0
2016	$ 175.3	$ 1,094.1	$ 1,445.9	$ 214.0
2017	$ 175.3	$ 1,094.1	$ 1,445.9	$ 214.0

Basis of margin forecast

PG&E provided 1995 and 1996 actual margin requirement (4/24/97).
These were averaged and applied to 1996
FR 95 real escalation was applied to obtain forecasted margin needs
After 2015 margin was held constant.
PG&E Backbone includes L300, 400, 401 and gathering.
PG&E Adjusted has had backbone removed.

SCG provided a ten year forecast for margin (2/24/97).
These were converted to 1995 dollars using DAO 1997 defaltor index.
FR 95 real escalation was applied to obtain forecasted margin needs after 20
After 2015 margin was held constant.

SDG&E provided a 14 year forecast for margin (2/7/97).
These were converted to 1995 dollars using DAO 1997 defaltor index.
FR 95 real escalation was applied to obtain forecasted margin needs after 20
After 2015 margin was held constant.

July 25, 1997